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June 24, 2008

RECEIVED
JUN 24 2008
PUBLIC SERVICE COMMISSION

Hon. Stephanie Stumbo
Executive Director
Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

Re: The Applications of Big Rivers Electric Corporation for: (1) Approval of Wholesale Tariff Additions for Big Rivers Electric Corporation, (II) Approval of Transactions, (III) Approval to Issue Evidences of Indebtedness, and (IV) Approval of Amendments to Contracts; and of E.ON U.S., LLC, Western Kentucky Energy Corp. and LG&E Energy Marketing, Inc. for Approval of Transactions, PSC Case No. 2007-00455

Dear Ms. Stumbo:

Enclosed for filing on behalf of Big Rivers Electric Corporation ("Big Rivers") are an original and ten copies of Big Rivers' supplemental responses to (i) Item 88 of the Attorney General's Supplemental Request for Information; (ii) Item 43 of the Commission Staff's Initial Information Request; and (iii) Item 13 of the Commission Staff's Supplemental Information Request. These data request responses were previously supplemented on May 30, 2008. I certify that this letter and the supplemental responses have been served on the attached service list.

Sincerely yours,

James M. Miller

James M. Miller

JMM/ej
Enclosures

cc: Michael H. Core
David Spainhoward
Service List

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Ann Building
PO Box 727
Owensboro, Kentucky
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VERIFICATION

I verify, state and affirm that the data request responses filed with this verification on June 24, 2008 and for which I am listed as a witness are true and correct to the best of my knowledge and belief formed after a reasonable inquiry.

Mark A. Bailey

Mark A. Bailey

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Mark A. Bailey on this the 24th day of June, 2008.

Paula Mitchell

Notary Public, Ky. State at Large
My commission expires 1-12-09

VERIFICATION

I verify, state and affirm that the data request responses filed with this verification on June 24, 2008 and for which I am listed as a witness are true and correct to the best of my knowledge and belief formed after a reasonable inquiry.

C William Blackburn

C. William Blackburn

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by C. William Blackburn on this the 24th day of June, 2008.

Paula Mitchell

Notary Public, Ky. State at Large
My commission expires 1-12-09

VERIFICATION

I verify, state and affirm that the data request responses filed with this verification on June 24, 2008 and for which I am listed as a witness are true and correct to the best of my knowledge and belief formed after a reasonable inquiry.

David A. Spainhoward

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by David A. Spainhoward on this the 24th day of June, 2008.

Notary Public, Ky. State at Large
My commission expires 8-9-2010

VERIFICATION

I verify, state and affirm that the data request responses filed with this verification on June 24, 2008 and for which I am listed as a witness are true and correct to the best of my knowledge and belief formed after a reasonable inquiry.

Robert W Berry

Robert W. Berry

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Robert W. Berry on this the 24th day of June, 2008.

Paula Mitchell

Notary Public, Ky. State at Large
My commission expires 1-12-09

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June 24, 2008

BIG RIVERS ELECTRIC CORPORATION'S
UPDATE TO RESPONSE TO THE ATTORNEY GENERAL'S
SUPPLEMENTAL REQUEST FOR INFORMATION
PSC CASE NO. 2007-00455
(June 24, 2008)

Item 88) Provide any and all internal E. ON documents which address the subject of existing agreements which are the subject of the "Unwind Transaction" and "Termination Transaction", including any financial analyses and strategic analyses.

Response) Big Rivers files this supplement to its response to Item 88 of the Attorney General's Supplemental Request for Information in response to requests by the Attorney General and the Commission Staff for more information regarding the generating plant and plant site due diligence Big Rivers is performing in anticipation of the Unwind Transaction closing. This Supplemental Response relates to Draft Settlement Concept No. 15 presented at the June 14, 2008, Informal Conference in this matter. Refer also to Tab 13 of Big Rivers' May 30, 2008 filing. Specifically, the attached document was prepared to provide additional information to the Public Service Commission concerning follow-up action taken or planned in response to the Stanley Consultants report dated April 2007 entitled "Analysis of WKE Outages". The Stanley recommendations can be found in the Executive Summary of that report on pages vi through x.

Witness) Mark A. Bailey
Robert Berry

Responses to Recommendations in April 2007 Stanley Consultants Report Entitled "Analysis of WKE Outages"
June 24, 2008

Coleman Unit 1

1. Identify the cause of wet bottom tube leaks and take corrective action.

   Big Rivers' Response:

   The tubes in question were original to the unit and had been in service for approximately 39 years. During the unit's 2008 spring outage which is currently in progress, all lower slope tubes were replaced from the lower water wall header to the water wall transition line.

2. The cause of the unit trip on June 5, 2004 due to No. 4 turbine bearing vibration should be identified. Determine if future actions are required.

   Big Rivers' Response:

   The unit was returning to service from a planned outage and during start-up when the turbine was being brought to normal operating speed, the turbine developed an internal rub causing a bow in the rotor resulting in higher than normal vibration on bearing number 4. The unit was removed from service and the turbine placed on turning gear to allow the rotor to straighten and return to normal condition. No further action was required and the unit was returned to service. The turbine generator is currently undergoing a complete overhaul/inspection described in item 4 which follows.

3. Due to the installation of the AOFA systems in 2004 on Coleman Unit 1 boiler fire-side tube corrosion or erosion could have detrimental impacts. Implement a regular program of mapping boiler tube thickness to monitor.

   Big Rivers' Response:

   WKE currently utilizes a Computerized Maintenance Management System (CMMS) to manage boiler mapping. Within the CMMS, a job plan is established to monitor boiler fire-side tube corrosion or erosion impacts. This job plan includes: scaffolding of the boiler, non-destructive examination (NDE) of boiler tubes, visual inspections, collecting tube samples, and metallurgical analysis as part of each 3-year scheduled maintenance outage. This activity is also included in the Big Rivers' Production Work Plan.

4. Plan for Coleman Unit 1 turbine generator overhaul.

   <u>**Big Rivers' Response:**</u>

   The Coleman Unit 1 turbine generator inspection is currently in progress with a scheduled completion date of July 19, 2008. The following is a partial list identifying major items addressed during this outage: replacement of L-0 (last row of turbine blades before the steam exhausts to the condenser), L-1 (next to last row), and L-2 (2nd from last row) rows of LP turbine blades on both the generator and turbine ends of the turbine rotor, total generator inspection and electrical testing per the original equipment manufacturer (OEM) recommendations, generator exciter refurbishment, replacement of HP-IP (high pressure – intermediate pressure) stub shaft extension with new ruggedized rotor, turbine throttle valve modification for positive seating, complete inspection of HP & IP turbine rotor, shells, and turbine valve inspection.

Coleman Unit 2

1. Since the upper and lower reheater has been replaced recently, the cause of the reheater leaks noted in 2004 should be identified and corrective action taken.

   <u>**Big Rivers' Response:**</u>

   Coleman Unit 2 experienced two reheat tube leaks in 2004. Both leaks were a result of sootblower (steam blown into the boiler against the tubes to remove ash accumulation) erosion. This issue was corrected by installing tube shields in the sootblower lane to protect the tubes from erosion. Coleman Unit 2 did not experience any reheat tube leaks in 2005 or 2006.

2. Identify the cause of wet bottom tube leaks. Determine if future repairs are required.

   <u>**Big Rivers' Response:**</u>

   The tubes in question are original to the unit and have (had) been in service for approximately 38 years. During the unit's 2007 spring outage, non-destructive examination (NDE) inspections were performed and 35 (of abnormally thin-walled tubes) of the 270 lower slope tubes were replaced from the lower header to outside the affected area as a result of this inspection.

3. Due to the installation of the AOFA systems in 2004 on Coleman Unit 2 boiler fire-side tube corrosion or erosion could have detrimental impacts. Implement a regular program of mapping boiler tube thickness to monitor.

   Big Rivers' Response:

   As described earlier in response to a similar recommendation for Coleman Unit 1, WKE currently utilizes a Computerized Maintenance Management System (CMMS) to manage boiler mapping. Within the CMMS, a job plan is established to monitor boiler fire-side tube corrosion or erosion impacts. This job plan includes: scaffolding of the boiler, NDE of boiler tubes, visual inspections, tube samples, and metallurgical analysis as part of each 3-year scheduled maintenance outage. This activity is also included in the Big Rivers' Production Work Plan.

Coleman Unit 3

1. New superheater tubes were installed in 2003. The cause of the superheater tube leaks since 2003 appear to have been evaluated in a Sheppard T. Powell report dated March 6, 2007. The Sheppard T. Powell report dated March 6, 2007 stated "...A portion of the tube has been submitted for alloy identification...." Obtain alloy identification report from Sheppard T. Powell.

   Big Rivers' Response:

   New Secondary superheater tubes were installed on this unit in 2003. The referenced Sheppard T. Powell (S.T.P.) report involved a primary superheater tube sample which was sent for analysis, not the secondary superheater tubes installed in 2003. On March 20, 2007, the station received the S.T.P. report confirming the tube composition is consistent with SA210 (designation number developed by the American Society for Testing and Materials (ASTM) which describes the mechanical properties of steel boiler tubing). This is consistent with the boiler design. A detailed boiler tube sampling program is included in the Big Rivers' Production Work Plan.

2. Stanley Consultants has insufficient information to determine if all necessary repairs and/or replacement items were performed during the fall 2006 turbine generator unplanned overhaul. In preparation for the next planned turbine generator overhaul, obtain list of spare parts, repair and/or replacement items as required.

   Big Rivers' Response:

   The Coleman Unit 3 turbine generator is currently operating within the original equipment manufacturer (OEM) specifications. Station personnel

have reviewed reports from the OEM related to the C3 turbine generator recommendations and will have spare parts, repairs, and replacement items as required for the planned outage currently scheduled for 2012. These items are included in the Big Rivers' long term plan.

3. Due to the installation of the AOFA systems in 2004 on Coleman Unit 3 boiler fire-side tube corrosion or erosion could have detrimental impacts. Implement a regular program of mapping boiler tube thickness to monitor.

Big Rivers' Response:

As described in previous responses within this document to similar recommendations, WKE currently utilizes a Computerized Maintenance Management System (CMMS) to manage boiler mapping. Within the CMMS, a job plan is established to monitor boiler fire-side tube corrosion or erosion impacts. This job plan includes: scaffolding of the boiler, non-destructive examination (NDE) of boiler tubes, visual inspections, tube samples, and metallurgical analysis as part of each 3-year scheduled maintenance outage. This activity is also included in the Big Rivers' Production Work Plan.

Green Unit 1

1. Plan for overlay welding or laser cladding of furnace walls to address furnace wall corrosion due to the delayed combustion characteristics of the coal re-burn system which generate higher levels of hydrogen sulfide (H2S) resulting in higher corrosion rates of the furnace walls. Investigate the possibility of relocation of IR sootblowers or additional IR sootblowers to reduce fireside deposits and combustion tuning to reduce flame impingement.

Big Rivers' Response:

Weld overlay (boiler tubes with extra material welded over them) was installed on the furnace east and west walls during the spring 2007 scheduled outage. An area, 95 feet high by 35 feet wide was overlaid with Alloy 33 (ASTM designation) corrosion resistant material. Water wall mapping revealed no loss of tube metal on the north or the south Walls. Ultrasonic testing will be performed again during the 2010 scheduled outage. An additional $2.6 million is included in the Big Rivers' Production Work Plan to apply additional weld overlay during the 2010 planned outage if testing results indicate it is needed. There are no plans to move the IR sootblowers. General Electric Energy Environmental Research (GE EER), the original equipment manufacturer (OEM) for the Re-burn/OFA (over fire air) system, completed combustion tuning in April of 2008.

2. Green Unit 1 has not been chemically cleaned since 1997. The analysis of both water wall tube samples removed by Babcock & Wilcox during the fall 2004 outage revealed internal deposit weight densities of 21 grams per square foot (gms/ft2) and 24 gms/ft2. The third-party inspection report states "...chemical cleaning should be performed when deposit weight densities reach 12 gm/ft2..." It is expected that Green Unit 1 requires cleaning at this time.

   Big Rivers' Response:

   Boiler chemical cleaning is performed using a condition-based approach rather than a time-based approach. The Green Unit 1 boiler tube sample analysis report by Sheppard T. Powell (S.T.P.) and Associates dated February 23, 2004 confirmed the boiler needs chemical cleaning. The Big Rivers' Production Work Plan includes chemical cleaning the Green Unit 1 boiler during the 2010 scheduled outage.

Green Unit 2

1. Monitor the condition of 2005 overlay welding of furnace walls to address furnace wall corrosion due to the delayed combustion characteristics of the coal re-burn system which generate higher levels of hydrogen sulfide (H2S) resulting in higher corrosion rates of the furnace walls. Investigate the possibility of relocation of IR sootblowers or additional IR sootblowers to reduce fireside deposits and combustion tuning to reduce flame impingement.

   Big Rivers' Response:

   During the spring 2008 scheduled outage, water wall tube mapping was conducted to monitor the effectiveness of the water wall tube weld overlay that was installed in 2005. An area 35 feet wide by 85 feet high on both the east and west furnace side walls are weld overlaid with Inconel 622 (ASTM designation) corrosion-resistant material. Ultrasonic testing showed no metal loss in the weld overlay area or on the north and south burner walls. Ultrasonic testing will be conducted again during the 2009 scheduled outage and $2 million is included in the Big Rivers' Production Work Plan for additional weld overlay if the testing indicates it is needed. There are no plans to move the IR soot blowers. General Electric Energy Environmental Research (GE EER), the original equipment manufacturer (OEM) for the Re-burn/OAF (over fire air) system, completed combustion tuning in April of 2008.

2. Green Unit 2 has not been chemically cleaned since 1990. The David N. French Metallurgist 2005 analysis of a water wall tube sample revealed a deposit weight

density of 15 gms/ft2. This third-party inspection report indicated the water wall tube was considered clean and a chemical clean was not needed at this time. This contradicts the Babcock & Wilcox recommendation of performing a chemical clean when deposit weight densities reach 12 gm/ft2. The Green Unit 2 spring 2005 outage work order (WO5079905 indicates Green Unit 2 was to be chemically cleaned during the spring 2005 outage. Verify Green Unit 2 was chemically cleaned during the 2005 spring outage.

<u>Big Rivers' Response:</u>

Boiler chemical cleaning is performed using a condition-based approach rather than a time-based approach. A tube sample analysis report (number 05-070) performed by Dr. David N. French (metallurgist whom WKE uses to evaluate tube sample deposits) suggests chemical cleaning of the boiler should be considered when the deposit weight density reaches 25 grams/ft2. Per Dr. French's' recommendation, the chemical cleaning was deferred until the next scheduled outage. The Big Rivers' Production Work plan includes chemical cleaning of the Green Unit 2 boiler during the 2009 scheduled outage.

HMPL Unit 1

1. New high temperature reheater tubes were installed in 1999, the cause of the high temperature reheater tube leak that occurred in 2006 should be identified and corrective action taken.

<u>Big Rivers' Response:</u>

According to the metallurgical analysis performed by Dr. David N. French (metallurgist whom WKE uses to evaluate tube sample deposits) and a Riley Power report (number 202302) dated June 6, 2008, the Henderson Unit 1 high-temp reheater tubes are failing due to thinning as a result of coal ash corrosion. The tubes have initial evidence of creep in the form of oxide cracking on the ID (inside diameter). While not in the current Big Rivers' Production Work Plan, current plans are to replace the high-temp reheat tubes at an estimated cost of $1.8 million during the scheduled spring outage of 2009.

Funding for this project will come from other planned projects that are not of as high a priority (e.g. deferred projects); from budgeted funds that might not entirely be needed to complete planned projects (e.g. over-budgeted projects); or by adding to the budget later if it is determined that there are no budgeted lower priority projects that can be deferred or enough money left over from under-budgeted completed projects.

As demonstrated in Big Rivers' response to the Attorney General's Supplemental Request for Information, items 94 and 95, even if the entire $1.8 million is added to the Financial Forecast, the rate impact of this change for both the non-smelter members and the smelters would be minimal.

2. Review the January 29, 2007 root cause analysis report. Determine if any future repairs are required as a result of the most recent thermal event.

Big Rivers' Response

A total of fourteen tube samples were removed and sent to David N. French (metallurgist whom WKE uses to evaluate tube samples) to determine if any significant damage had occurred. These included four samples on the east wall, four samples on the west wall, and six samples from the south wall were removed at elevations 492' 10" and 512' 10" within the boiler. The final report was received from the laboratory on Thursday February 8, 2007; the conclusions of this report are as follows.

- **There was no evidence of metallurgical degradation of the sample water wall tubes resulting from the coolant disruption.**
- **Typical microstructures were observed in the tubing, as for new SA-178 Gr.C (ASTM designation).**
- **There has been no significant loss of expected life of the boiler tubes from the low water event.**
- **Some inside diameter (ID) corrosion pitting was observed but deemed superficial.**
- **Deposit weight density was measured on a sample from each of the three walls, and the measurements showed the waterside to be clean. Even with the high temperature excursion, the tubes have not been oxidized on the waterside.**

HMPL Unit 2

1. Verify the high temperature reheater is being replaced during fall 2007 outage. If not accomplished during the fall 2007 outage, confirm the high temperature reheater is on the spring 2008 outage schedule.

Big Rivers' Response:

The H-2 high-temp reheater was replaced in October of 2007.

Reid Unit

1. The cause of the superheater tube leaks should be identified and corrective action

taken.

<u>**Big Rivers' Response:**</u>

Tube sample analysis concludes the Reid Unit 1 primary superheater is approaching the end of its useful life. Due to changes in environmental regulations such as CAIR, 316b, NOx, PM 2.5 and mercury, Big Rivers has in its 2009 Production Work Plan to evaluate the spending levels needed to maintain the future reliability of the Reid unit.

2. The cause of the water wall tube leaks should be identified and corrective action taken.

<u>**Big Rivers' Response:**</u>

Reid Unit 1 experienced numerous tube leaks on the lower water wall header tube stubs. These tubes experienced thinning due to exposure in the corrosive area of the boiler bottom ash hopper seal water. The lower water wall header stubs were replaced in the spring of 2004 which eliminated the water wall leaks associated with the thinning tube stubs.

Wilson Unit

1. The IMR metallurgical report dated June 16, 2006 states "...superheater Tube #1... a moderately dirty deposit density of 41.4 gm/ft2 was measured from internal deposits, which indicates that the tube would benefit from internal cleaning." Perform recommendations from metallurgical report. Continue annual submission of superheater tube samples for metallurgical review.

<u>**Big Rivers' Response:**</u>

Tube samples were collected from the platens and finishing superheater sections during the spring 2008 outage. The samples were sent to Dr. David N. French, (metallurgist whom WKE uses to evaluate tube sample deposits) for analysis. The reports from both the platens and the finishing tube samples indicated there was a very thin oxide layer and the internal condition was reported to be good. The Big Rivers' Production Work Plan includes the replacement of the Wilson superheater tubes during the fall 2009 outage.

2. The Wilson unit has not been chemically cleaned since 1997. The most recent metallurgical report Stanley Consultants has received to date from BREC is dated June 16, 2006 and prepared by IMR Metallurgical Services. This third-party inspection report stated "Waterside deposits/scale on the inside surfaces of the tubing were measured in accordance with ASTM D3483, Test Method A. The

measured value recorded from superheater tube was a maximum of 41.4 g/ft2, while the values recorded from the water wall tubing were "cleaner" with a maximum deposit of 13.95 g/ft2. The values recorded are a combination of oxide scale and/or internal deposition." The need to perform a chemical clean of this unit should be verified.

<u>**Big Rivers' Response:**</u>

Boiler chemical cleaning is performed on a condition-based approach rather than a time-based approach. During the 2008 spring outage, tube samples were collected and sent to Sheppard T. Powell for analysis. The report from the north wall tube sample has been received and indicated that no chemical cleaning is needed at this time. The report from the south wall tube sample analysis is still pending. The Big Rivers' Production Work Plan contains plans to chemical clean the Wilson unit during the fall 2009 outage since an earlier report (prior to the 2008 sample reports) indicated the unit was borderline concerning the need for chemical cleaning and the outage length was such that the cleaning could be accommodated without extending the outage length.

3. Review the future Wilson outage work lists and post work documentation related to the turbine generator incident to assure the recommended repairs and inspections as a result of the loss of lube oil event are completed.

   <u>**Big Rivers' Response:**</u>

   Remote continuous vibration monitoring is performed on the main turbine/ generator. The data has not indicated any serious problems. The Big Rivers' Production Work Plan includes a high pressure-intermediate pressure (HP/IP) turbine/generator inspection for 2009. A complete evaluation will be performed on the HP/IP rotor at this time. Appropriate corrective actions will be based upon the findings of this evaluation.

All Units

1. Boiler Tube Leaks:
   a) A comprehensive assessment should be performed to determine the root cause of boiler tube failures. An investigation of all aspects of boiler operation, leading to a tube failure to fully understand the cause should be performed. For example, boiler water treatment, so scale, foaming, corrosion, caustic embrittlement, and turbine blade deposition can be avoided or minimized. Water chemistry, outage, and maintenance records should be requested to aid in root cause analyses of corrosion and deposit problems.

Big Rivers' Response:

In addition to the Computerized Maintenance Management System (CMMS) to manage boiler tube mapping described previously, Big Rivers will implement a formal root cause analysis process for all tube leak outages. The person identified to fill the newly created (within the Big Rivers post-unwind organization) Manager of Maintenance Services will work with staff at each plant to implement and monitor this process. The process will include metallurgical analysis of failed tubes and an adjacent tube in the same area.

b) The rate of damage and the effects of water and steam chemistry on erosion/corrosion, boiler tube corrosion, turbine blade pitting and cracking, feedwater heater and condenser tube corrosion, etc., should be identified and lead to planned outages and equipment repairs or replacement.

Big Rivers' Response:

Drum inspections, internal condenser inspections, boiler tube samples and turbine inspections conducted on all units in the Big Rivers' system indicate there have been no problems related to water chemistry. Regular monitoring of these areas will continue so that in the event water chemistry becomes an issue, it can be addressed promptly.

c) Physical evidence in all tube failures should be analyzed. High velocities occur during a tube leak that will remove deposits in the leaking or ruptured tube. Therefore, it is recommended that a tube similar to a tube which has failed, in the same area, be removed for proper analysis.

Big Rivers' Response:

When the cause of a boiler tube failure is not readily determined, Big Rivers plans to send the tube failure along with a tube in the adjacent area to either Sheppard T. Powell and Associates or Dr. David N. French (metallurgist whom WKE uses to analyze tube samples) for analysis including life assessment and deposit composition. This will continue to be a part of the root cause analysis process.

d) As tube failures occur, they should be tracked and any patterns analyzed for similarity. A better assessment of the causes of the tube leaks could be performed if there was more information on where these leaks occurred. Mapping of the tube leaks would show how close the tube leaks are to any sootblowers or other equipment that may have caused abrasion to the inside of the tubes. Failures should be used to determine the locations for the next set of tube samples. In addition, there is a need to sample for external attack such as reducing atmosphere, sulfur attack and erosion wear patterns.

Big Rivers' Response:

All stations track tube failures detailing the location of the leak(s), tube material, size of tube and thickness, date of repair, length of repair and estimated cause of failure. In the future, Big Rivers plans that the analysis process will include a composite drawing identifying the location of each failure.

e) The boiler water treatment program should be audited for compliance with the recommended EPRI guidelines and/or plant chemical vendor guidelines.

Big Rivers' Response:

The boiler water treatment plan being utilized by Western Kentucky Energy which is planned to be continued under Big Rivers is the program recommended by Dave Cline with Sheppard T. Powell and Associates. Sheppard T. Powell's staff was instrumental in formulating the EPRI Boiler Treatment guidelines. All stations are following the EPRI guidelines.

f) A continuous and consistent program of sampling boiler, economizer, superheater and reheater tubes should be implemented.

Big Rivers' Response:

As a result of the Boiler Condition Assessment team work, during each scheduled outage the CMMS system (described in earlier responses) automatically generates a work order for boiler tube samples to be taken from the water walls, nose arch, superheater, economizer and reheat sections of each unit's boiler. The tube samples are sent to either Sheppard T. Powell and Associates or Dr. David N. French (metallurgist whom WKE uses for tube analysis) for analysis including life assessment and deposit composition.

g) An annual review of the recorded boiler operating temperatures and pressures, as compared to design parameters, should be performed.

Big Rivers' Response:

Each station's Performance Engineer and Production Manager perform a routine daily evaluation of the parameters listed in this recommendation. In addition to the station's efforts, Coleman and Green

station both have a standing performance monitoring contract with Black and Veatch to continuously monitor station operating parameters, including operating temperatures and pressures. The Wilson plant will also utilize Black and Veatch for performance monitoring after Big Rivers resumes operation and HMP&L Station Two will do so when the new system controls are installed in 2010 which will accommodate this activity.

2. BREC should consider having a BREC plant transition site representative at all of the BREC stations. This site representative would require access to maintenance records, operating logs, performance reports, and other pertinent information.

Big Rivers' Response:

Big Rivers currently has a representative at each location and they have access to all pertinent information.

Item 43) Refer to the Spainhoward Testimony, page 40 of 48.

a. Provide an analysis of Big Rivers' SO_2 emission allowance inventory. This analysis should cover the years 2008 through 2023 and include the following information for each year of the analysis.

(1) Total SO_2 emission allowances in inventory as of the beginning of the year.

(2) Total SO_2 emission allowances received from the Environmental Protection Agency ("EPA").

(3) Total SO_2 emission allowances surrendered to EOA to cover emissions.

(4) Number of SO_2 emission allowances Big Rivers anticipates it will sell.

(5) Number of SO_2 emission allowances Big Rivers anticipates it will sell.

(6) Total SO_2 emission allowances in inventory as of the end of the year.

b. Mr. Spainhoward states that during the period from 2008 through 2012 Big Rivers plans to sell any excess SO_2 emission allowances and use the revenues from these sales to reduce the level of the environmental surcharge. The Unwind Model shows that beginning in 2015 Big Rivers expects its SO_2 emissions to exceed its allocation of emission allowances. In light of this situation and the fact that SO_2

emission allowances can be banked, explain in detail why Big Rivers believes that its proposal to sell excess allowances over the next 4 years is reasonable.

c. Assume for purposes of this question that the Commission required Big Rivers to bank its excess SO_2 emission allowances during 2008 through 2012 rather than allowing the allowances to be sold. Explain in detail the effect of such a requirement on the Unwind Transaction.

Response) Big Rivers' Unwind Financial Model (Application Exhibit 8) contemplates emission allowances being sold from its inventory in the early years of the period after the Unwind Transaction Closing, and purchased in later years to meet the requirements of environmental laws regarding emissions. During an informal conference in this matter, Commission Staff expressed concern that evidence of shifting prices in the allowance market made the wisdom of this plan questionable. Staff suggested the possibility of imposing limitations on the percentage of Big Rivers' allowance inventory that could be sold in any year, subject to that limitation being removed, if found appropriate by the Commission, upon motion by Big Rivers in its first general rate case following the Unwind Transaction Closing. Draft Settlement Concept No. 29 submitted at the May 15, 2008, Informal Conference.

The Staff's concerns arose from emission allowance price forecasts they had seen in other cases that contradicted the forecasts used by Big Rivers in 2007 when the Unwind Financial Model was prepared. The latest forecast obtained is attached to Item 64 of the Attorney General's Initial Data Request. The emission allowance prices in that forecast continue to be different than those referred to by Staff.

Big Rivers believes that decisions about managing emission allowance inventories are fundamentally decisions that should be left to management of the utility, using information available at the time the decision is made. Based upon the latest allowance forecast information available to Big Rivers, Big Rivers does not intend to sell emission allowances prior to Big Rivers' next general rate case. However, if actual allowance prices are greater than the forecast prices then Big Rivers might decide to sell the allowances. In any event, decisions to buy or sell allowances will be based upon all facts available to management at the time the decision is made.

Witness) C. William Blackburn
David A. Spainhoward

Item 13) Refer to the response to the Staff's First Request, Item 28.

a. Does Big Rivers agree that the RUS USoA provides that utilities owning emission allowances shall account for those allowances at cost?

b. Does Big Rivers agree that while the market value of the 14,000 sulfur dioxide ("SO_2") emission allowances may represent a portion of the consideration being provided by E. ON to Big Rivers as part of the Unwind Transaction, the market value does not necessarily reflect the cost of those emission allowances? Explain the response.

Response) Attached is the Federal Register reference that Commission Staff requested at June 19, 2008 Informal Conference.

Witness) C. William Blackburn

dural in nature and therefore fall within the categorical exemptions provided in the Commission's regulations. Consequently, neither an environmental impact statement nor an environmental assessment is required.[38]

VI. Information Collection Statement

The Office of Management and Budget's (OMB) regulations require that OMB approve certain information collection requirements imposed by agency rule.[39] However, the regulations adopted herein contain no information collection requirements and therefore are not subject to OMB approval.

VII. Effective Date

This rule is effective April 23, 1993.

List of Subjects in 18 CFR Part 11

Electric power, Reporting and recordkeeping requirements.

By the Commission.

Lois D. Cashell,

Secretary.

Appendix A—List of Commenters

Note: This appendix will not be published in the Code of Federal Regulations.

Alabama Power Company (Alabama)

American Public Power Association (APPA)

Consolidated Pumped Storage, Inc. (Consolidated)

Consumers Power (Consumers)

City of Danville, Virginia Electric Department and Merced

Irrigation District, California (Danville)

Edison Electric Institute (EEI)

Georgia Power Company (Georgia)

Halecrest, Inc.

National Hydropower Association (NHA)

Pacific Gas and Electric Company (PG&E)

Public Generating Pool (Pool)

Public Service Company of Colorado (Colorado)

Public Utility District of Cowlitz County, Washington (Cowlitz)

Public Utility District No. 1 of Douglas County, Washington (Douglas)

Public Utility District No. 2 of Grant County, Washington (Grant)

Puget Sound Power & Light Company (Puget)

Sacramento Municipal Utility District (Sacramento)

Tacoma Public Utilities (Tacoma)

Tapoco, Inc.

Virginia Electric and Power Company (Virginia)

Washington Water Power Company (Washington)

Yuba-Bear River Project (Yuba)

[¶ 30,967]

58 F.R. 17982 (April 7, 1993)

18 CFR Parts 101 and 201

[Docket No. RM92-1-000; Order No. 552]

Revisions to Uniform Systems of Accounts to Account for Allowances under the Clean Air Act Amendments of 1990 and Regulatory-Created Assets and Liabilities and to Form Nos. 1, 1-F, 2 and 2-A

Issued: March 31, 1993.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final Rule.

SUMMARY: This final rule adopts accounting requirements for: (1) allowances for emission of sulfur dioxide under the Clean Air Act Amendments of 1990; and (2) assets and liabilities created through the ratemaking actions of regulatory agencies. The final rule also adopts new reporting schedules and revises other schedules to be used by jurisdictional companies in reporting information on allowances and regulatory assets and liabilities.

EFFECTIVE DATE: The final rule is effective January 1, 1993. The information collection provisions, however, will not become effective until approved by the Office of Management and Budget. Notice of this date will be published in the **Federal Register**.

FOR FURTHER INFORMATION CONTACT: Gregory A. Berson, Office

[38] *See* 18 C.F.R. 380.4(a)(1).

[39] 5 C.F.R. Part 1320.

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SUPPLEMENTARY INFORMATION: In addition to publishing the full text of this document, excluding Appendix A (revised pages for FERC Form Nos. 1, 1-F, 2 and 2-A) and Appendix B (list of commenters), in the **Federal Register**, the Commission also provides all interested persons an opportunity to inspect or copy the contents of this document during normal business hours in Room 3104, 941 North Capitol Street, NE., Washington, D.C. 20426.

The Commission Issuance Posting System (CIPS), an electronic bulletin board service, provides access to the texts of formal documents issued by the Commission. CIPS is available at no charge to the user and may be accessed using a personal computer with a modem by dialing (202) 208-1397. To access CIPS, set your communications software to use 300, 1200 or 2400 bps; full duplex, no parity, 8 data bits, and 1 stop bit. CIPS can also be accessed at 9600 bps by dialing (202) 208-1781. The full text of this rule, excluding Appendices A and B, will be available on CIPS for 30 days from the date of issuance. The complete text on diskette in WordPerfect format may also be purchased from the Commission's copy contractor, La Dorn Systems Corporation, also located in room 3104, 941 North Capitol Street, NE., Washington, DC 20426.

Before Commissioners: Elizabeth Anne Moler, Chair; Jerry J. Langdon, Martin L. Allday, and Branko Terzic.

Final Rule

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I. Introduction

On December 2, 1991, the Commission issued a notice of proposed rulemaking (NOPR) proposing to amend its Uniform Systems of Accounts (USofA) for public utilities, licensees and natural gas companies to establish: (1) uniform accounting requirements for allowances, arising from Title IV of the Clean Air Act Amendments of 1990 (CAAA),[1] for emission of sulfur dioxide; and (2) generic accounts to record assets and liabilities created through the ratemaking actions of regulatory agencies.[2]

Sixty-seven parties filed comments on the NOPR. The comments filed by a number of parties were untimely, but the Commission will consider these untimely comments in this proceeding, given the absence of any undue prejudice or delay.

[1] Pub. L. No. 101-549, Title IV, 104 Stat. 2399, 2584 (1990).

[2] *FERC Statutes and Regulations* ¶ 32,481 (1991), 56 FR 64567 (Dec. 11, 1991).

In response to the comments received, the Commission has decided to adopt a final rule generally consistent with the NOPR, but with several significant changes. The major accounting proposals retained from the NOPR include: the classification of allowances in new inventory Accounts 158.1 and 158.2; the valuation of most allowances at historical cost; the use of the weighted average cost method for determining the cost of allowances issued from inventory; the expensing of allowances in new Account 509; and the use of several new accounts for regulatory assets and liabilities.

The major changes from the accounting proposed in the NOPR include: the use of fair value in the valuation of allowances traded between affiliates; and the elimination of the NOPR's two-step process of accounting for regulatory assets and liabilities in favor of a one-step process that is more consistent with past practices.

The Commission also is adopting new reporting schedules and revising other schedules to be used by jurisdictional companies in reporting information on allowances and regulatory assets and liabilities in four of its Annual Reports (FERC Form Nos. 1, Annual Report of Major public utilities, licensees and others (Form 1); 1-F, Annual Report of Nonmajor public utilities and licensees (Form 1-F); 2, Annual Report of Major natural gas companies (Form 2); and 2-A, Annual Report of Nonmajor natural gas companies (Form 2-A)).[3] These new and revised schedules incorporate the final rule's changes and are contained in Appendix A.[4]

As the Commission stated in the NOPR, the objective in adopting this final rule is to provide useful financial and statistical information to regulatory agencies and other users of the financial statements by establishing sound and uniform accounting and reporting requirements for allowance transactions and for regulatory assets and liabilities. The final rule is not intended to promote or discourage particular CAAA compliance strategies or to prescribe the ratemaking treatment for allowances. The final rule is intended to be "rate neutral."

II. Public Reporting Burden

The Commission believes that any additional annual reporting burdens for collection of information resulting from this rule will be minimal. The Commission notes that usual business practices would require utilities to account for and report allowance transactions and regulatory assets and liabilities even in the absence of the rule. By adopting the rule, the Commission gives certainty as to how utilities should account for and report such transactions and thereby facilitates the usefulness of utility financial statements to all users.

Send comments regarding this burden estimate or any other aspect of the Commission's collection of information, including suggestions for reducing this burden, to the Federal Energy Regulatory Commission, 941 North Capitol Street, NE., Washington, DC 20426 (Attention: Michael Miller, Information Policy and Standards Branch, (202) 208-1415), and to the Office of Information and Regulatory Affairs of the Office of Management and Budget (Attention: Desk Officer for Federal Energy Regulatory Commission).

III. Discussion

A. *Effect on Ratemaking*

The Commission stated in the NOPR that the proposed rules were not intended to prescribe the ratemaking treatment for allowances and would not bar regulatory commissions (including this Commission) from adopting any particular ratemaking treatment.[5] The proposed rules were intended to be "rate neutral."

Comments.[6] The Iowa Working Group [7] and the North Carolina Staff support the goal of rate neutrality. The North Caro-

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[3] The current versions of these forms bear the following OMB approval numbers: Form 1, No. 1902-0021; Form 1-F, No. 1902-0029; Form 2, No. 1902-0028; and Form 2-A, No. 1902-0030.

[4] Appendix A is not being published in the **Federal Register**, but is available from the Commission's Public Reference Room.

[5] *FERC Statutes and Regulations* ¶ 32,481 at p. 32,572.

[6] All of the commenters are listed in Appendix B to this order. Abbreviations for the commenters are also listed in Appendix B.

[7] The Iowa Working Group consists of the Iowa Utilities Board, the Iowa Office of the Consumer Advocate, Interstate Power Company, Iowa Power and Light Company, Iowa Public Service Company, Iowa Southern Utilities, Iowa Electric Light and Power Company and Iowa-Illinois Gas and Electric Company.

lina Staff argues, for example, that the USofA should provide information about economic events affecting a utility, and not direct those economic events by prescribing certain ratemaking practices.

Similarly, EPA asks the Commission to reiterate that this rulemaking addresses only accounting, not ratemaking. However, EPA also encourages the Commission to issue a policy statement in a separate proceeding on allowance ratemaking.

The Ohio Staff argues that the NOPR's proposed accounting may not in fact be "rate neutral." As an example, the Ohio Staff asserts that the NOPR's proposal to classify allowances as inventory suggests that allowances should be included in rate base in an amount equal to the twelve-month average balance of allowances, instead of the balance on a date certain, as is typical for plant-in-service. The Ohio Staff asks the Commission to reiterate its goal of rate neutrality in both this order and the general instructions of the USofA. The Ohio Staff also recommends that the description of Account 158.1, Allowance Inventory, state that the Commission is not requiring nor recommending any particular rate base or ratemaking treatment.

EEI and others[8] urge the Commission to develop a ratemaking framework coincident with the development of accounting rules. EEI argues that doing so would allow the accounting rules to be developed more meaningfully. Wisconsin Public Service argues that a ratemaking framework will give utilities guidance in developing compliance plans and assist states in developing their own ratemaking frameworks.

EEI and others[9] ask the Commission to state that utilities will be allowed to recover prudently incurred costs as operating expenses and that unused allowances bought for operations are to be included in rate base. Similarly, Centerior argues that the final rule should be consistent with the goal of full recovery of all prudently incurred compliance costs. Florida Power & Light asserts that, at a minimum, the Commission should state that it intends the proposed new accounts to be commensurate to existing accounts for ratemaking purposes.

EEI, Central & South West and Gulf States ask the Commission to state that the economic value of allowances should be reflected in pricing when allowances are used in sales for resale, affiliate trades and power pool operations. Gulf States argues that this recovery is needed in order to fairly compensate retail customers who often will experience significant rate increases to pay for scrubbers or low sulfur coal. Centerior argues that the Commission should indicate that nothing in the final rules is intended to preclude a utility's ability to recover the economic value of allowances.

Deloitte & Touche recommends the initiation of a generic proceeding on ratemaking issues in order to remove some of the uncertainty about when utilities may recover prudently-incurred compliance costs. Deloitte & Touche argues that differences in regulatory certainty about the recoverability of the costs of some compliance methods, *e.g.*, fuel switching compared to buying allowances, could hinder least cost planning and the development of the allowance market. Deloitte & Touche states that existing Commission policies would require wholesale power sales to be priced at the seller's costs, including allowances obtained at zero cost, even though state regulators are unlikely to allow utilities to dispose of allowances without recompense.

Pennsylvania Power & Light asks the Commission to resolve the ratemaking for allowances in this rulemaking or in a separate generic rulemaking, instead of case-by-case. Pennsylvania Power & Light argues that a generic rulemaking would allow all interested parties, and not just the parties to individual rate filings, to participate in resolving the rate issues.

Duke Power also argues that this proceeding should address ratemaking issues. Duke Power argues that most state commissions look to generally accepted accounting principles (GAAP)[10] as reflected

[8] Florida Power & Light, Gulf States and Wisconsin Public Service.

[9] Cincinnati Gas & Electric, Con Edison, Gulf States and Wisconsin Electric.

[10] GAAP is a technical term in financial accounting. GAAP encompasses the conventions, rules and procedures necessary to define accepted accounting practices at a particular

in the USofA to provide a framework for cost recovery.

NRECA urges the Commission to undertake the task of allocating compliance costs and cost savings between ratepayers and stockholders and among classes of ratepayers of multi-jurisdictional utilities. NRECA states that, because of possible regulatory tension among state commissions in such situations, the Commission is uniquely able to perform this task.

Commission Response. The Commission understands the need for the eventual development of a ratemaking framework for allowances, but declines to prescribe such a framework in this final rule. The NOPR did not propose a ratemaking framework and did not solicit comments on that subject. Most commenters did not address the subject. Moreover, the bulk of the cost of allowances and compliance will be within the ratemaking jurisdiction of the various States and not this Commission. There is not likely to be a single ratemaking framework appropriate in each and every ratemaking jurisdiction for utilities subject to this Commission's accounting jurisdiction.

The Commission does, however, have accounting jurisdiction over almost the entire industry involved with allowances and this rulemaking was initiated to meet the need for timely action on accounting issues. As stated in the NOPR, this rule is intended to provide useful financial and statistical information to users of a utility's financial statements by establishing uniform accounting and reporting requirements for allowance transactions. The rule is "rate neutral" in that the prescribed accounting will reflect the economic effects of whatever ratemaking treatment is granted. The rule does not dictate or favor one particular rate treatment over another. The Commission sees no need to expand the scope of this accounting rule for the rate issues raised by the commenters. The ratemaking treatment for allowances will be dealt with in other forums.

B. *Allowance Classification*

1. *General Rule*

The NOPR proposed to classify allowances in two new inventory accounts in the "Current and Accrued Assets" section of the Balance Sheet: Account 158.1, Allowance Inventory and Account 158.2, Allowances Withheld. The NOPR explained that using these new accounts might avoid preconceptions that could arise about the nature of allowances if existing accounts were used. The NOPR stated that the new accounts would not dictate any particular ratemaking treatment and thus would be consistent with the goal of establishing "rate neutral" accounting.

Commenters Supporting the NOPR. NARUC and the Florida Commission support the creation of the new accounts. The Florida Commission states that the new accounts are theoretically supportable and compatible with foreseeable ratemaking treatments in Florida.

APPA also supports the new accounts, stating that separate accounts for allowances will facilitate regulatory review of allowance trading and use. APPA states that the new accounts would maintain account specificity in formula rates and avoid lengthy interrogatories to identify such costs.

Exceptions for State Ratemaking. The Illinois Commission argues that utilities with primary rate jurisdiction at the state level should be allowed to modify the Commission's accounting to conform to state requirements. The Illinois Commission asserts that state regulators may wish to allow recovery of allowance costs through a fuel clause and that such recovery in Illinois is allowed only for costs cleared through Account 151. The Illinois Commission argues that costs recorded in the new accounts may not be recoverable in the fuel clause in Illinois absent a change in state law.

Similarly, EEI and others[11] assert that utilities should be allowed to use the ac-

(Footnote Continued)

time. GAAP incorporates the accounting profession's consensus at a particular time as to which economic resources and obligations should be recorded as assets and liabilities, which changes in assets and liabilities should be recorded, when these changes should be recorded, how the assets and liabilities and changes in them should be measured, what information should be disclosed and how it should be disclosed and what financial statements should be prepared.

[11] Allegheny Power, American Gas Association, Commonwealth Edison, Con Edison, Kentucky Utilities and PacifiCorp.

counting required by a state commission of primary jurisdiction instead of the Commission's accounting rules. Kentucky Utilities argues that federal and state jurisdictional differences should be minimized, whenever possible, in order to avoid the need for "two sets of books." Kentucky Utilities asserts that maintaining multiple records for similar items would add to the burden of recording and reporting accounting transactions.

Classification as Fuel. A number of commenters propose to classify allowances in a new subaccount of Account 151, Fuel Stock, primarily because this treatment would allow fuel clause recovery of allowance costs.[12] Delmarva Power, for example, argues that the cost of allowances will be a necessary part of the cost of fuel stock. Potomac Electric states that the fuel clause should be used for all compliance costs, including all gains and losses from allowance trades, because the least cost approach to CAAA compliance combines fuel switching and allowance purchases.

EEI argues that using the fuel clause would avoid the frequent and costly rate cases otherwise needed to track possibly volatile and unpredictable costs and benefits. EEI asserts that using a new subaccount within an existing account could avoid possibly expensive renegotiations and litigation over existing contracts.

PSI Energy argues that using fuel subaccounts for allowances would not violate the goal of rate neutrality because regulatory commissions will thoroughly review any proposed ratemaking for allowances, even if allowance costs are recorded in fuel subaccounts. Similarly, Wisconsin Public Service argues that fuel subaccounts could accommodate a regulatory decision to treat allowances differently from fuel for ratemaking purposes.

Centerior supports classifying allowances in existing Account 151, Fuel Stock. According to Centerior, the Commission has offered no concrete evidence that using the existing inventory account for fuel would suggest a predisposition to a particular ratemaking treatment.

The North Carolina Staff opposes the use of fuel inventory accounts for allowance costs, arguing that allowances are not fuel and are not closely enough related to fuel to be recorded in fuel accounts. The North Carolina Staff asserts that the integrity of the fuel inventory accounts should not be compromised simply to facilitate certain ratemaking procedures.

The Wisconsin Municipal Group[13] argues that allowance costs are ineligible for fuel clause treatment and that the Commission should not waive its regulations to allow such treatment. The Wisconsin Municipal Group asserts that allowance costs have nothing to do with the cost of fuel and, thus, should not be recovered through the fuel clause.

Classification as Plant Cost. Con Edison asserts that allowance costs relate more to plant than fuel. Con Edison states that allowances bought or sold by a utility result principally from, or are a trade-off for, plant capital expenditures. Con Edison states that the need for allowances could be reduced by fuel switching, but even this alternative is a trade-off against plant capital expenditures.

Wisconsin Electric argues that allowances should be classified as plant costs in existing Account 303, Miscellaneous Intangible Plant, which includes "the cost of patent rights, licenses, privileges and other intangible property necessary or valuable in the conduct of utility operations . . . ." In support, Wisconsin Electric asserts that an allowance is an intangible item with an undetermined life (since it may be used in any year after issuance). Wisconsin Electric argues that inventory accounts, on the other hand, generally include physical materials that will be used within the next year.

[12] EEI, American Gas Association, Allegheny Power, Baltimore Gas & Electric, Cincinnati Gas & Electric, Central & South West, Consumers Power, Delmarva Power, IES Industries, Ohio Edison, Penn Power, PJM, Potomac Electric, PSE&G, PSI Energy and Wisconsin Public Service.

[13] The Wisconsin Municipal Group consists of many of the wholesale customers of Wisconsin Electric Power Company, Wisconsin Power & Light Company, Wisconsin Public Service Corporation, and Northern States Power Company (Wisconsin) The group is made up of 43 municipalities, 4 cooperatives, and 2 municipal electric companies, which in turn are made up of an additional 32 municipalities.

Duke Power questions whether allowances should be classified in a work-in-progress account similar to Account 107, Construction Work In Progress, or Account 120.1, Nuclear Fuel In Process. Duke Power argues that a work-in-progress account would allow for the accrual of carrying costs for what could be sporadic expenditures for allowances.

Other Classifications. Virginia Power argues that allowances should be classified based on the economics of the underlying transaction. Virginia Power argues, for example, that the cost of allowances obtained in fuel-related trades should be included in the invoice price of fuel in Account 151, Fuel Stock. Virginia Power cites the example of a coal supplier who bundles allowances with a sale of high sulfur coal. Virginia Power argues that using these allowances is integral to burning this particular coal and that the accounting for, and the costs of, the allowances and the coal should not be separated.

AEP proposes classifying allowances in existing accounts based on the ratemaking for each utility, *e.g.*, whether allowances are treated for ratemaking purposes as plant-related or fuel-related. Under this approach, AEP argues, utilities could recover allowance costs under existing account-specific formula rates without renegotiating contracts or litigating to obtain Commission approval.

Coopers & Lybrand argues that a utility that is allocated allowances exceeding those needed for current year emissions has excess allowances that can be sold immediately or carried forward for future use or sale. Coopers & Lybrand asserts that only these excess allowances should be recorded as assets, with income recognized in the year they are allocated but not used, since they represent a probable future economic benefit. Coopers & Lybrand argues that using an inventory account is inappropriate because allowances are more analogous to financial instruments. Coopers & Lybrand supports the creation of new accounts, but believes they should more appropriately reflect the marketable nature of allowances.

The Michigan Staff recommends requiring utilities to maintain records for Accounts 158.1 and 158.2 by affected generating unit, if known. The Michigan Staff argues that this information will permit matching of allowances to expenditures incurred to reduce emissions and thus facilitate favorable ratemaking and tax treatment.

Long-Term Asset Classification. NYDPS and others[14] propose the creation of a separate inventory account for allowances that cannot or will not be used in the current year, with allowances being reclassified to current assets when they are estimated to be used in the current year. NYDPS argues that this approach comports with GAAP and specifically with Accounting Research Bulletin No. 43, which defines a current asset as one "expected to be realized . . . or consumed during the normal operating cycle [generally one year]."[15] NYDPS argues that regulators may be reluctant to permit rate base inclusion of allowances not usable until years later.

Arthur Andersen, AICPA and Gulf States support the creation of an account similar to the account for nuclear fuel. Arthur Andersen argues that many purchased allowances will not be used in the current operating cycle and, thus, under Accounting Research Bulletin No. 43, are not a current asset and cannot be treated as inventory.

Allowances Purchased for Speculation. AICPA and others[16] argue that allowances purchased for speculative purposes, instead of as a hedge against price increases on allowances needed for operational purposes, should be recorded in Account 124, Other Investments.

Commission Response. In the NOPR, the Commission stated that the purpose of this rule is to provide guidance, uniformity and consistency in accounting and reporting for allowance transactions.[17] As reiterated above, this rule is

[14] Price Waterhouse, EEI, Allegheny Power, Atlantic Electric, Gulf States and Potomac Electric.

[15] Accounting Research Bulletin No. 43, *Restatement and Revision of Accounting Research Bulletins*, Ch. 3, ¶ 4, *in Accounting Statements—Original Pronouncements* (1991).

[16] Arthur Andersen, Deloitte & Touche, EEI, Atlantic Electric, Centerior, Commonwealth Edison, Florida Power & Light and PSI Energy.

[17] *FERC Statutes and Regulations* ¶ 32,481 at p. 32,574.

not intended to prescribe the ratemaking treatment for allowances or bar regulatory commissions from adopting any particular ratemaking treatment.

The Commission will not adopt the recommendation of a number of commenters that utilities should be allowed to use the accounting required by a state commission of primary jurisdiction, instead of the Commission's accounting rules. Uniform accounting is a linchpin of effective regulation of the public utility industry.[18] The Commission does not think it is in the public interest to allow the use of alternative accounting practices because of diverse state ratemaking practices.

Upon reviewing the comments, the Commission finds that the proposed new allowance accounts (Accounts 158.1 and 158.2) will best meet the stated objectives. Although allowances have characteristics that could support several different classifications, including classification as fuel or financial instruments, allowances are distinguishable from any of these. Allowance usage is only one of several possible components of a utility's overall CAAA compliance strategy; the cost of each component should be classified separately from the cost of other components (*e.g.*, capital and operating costs for scrubbers, fuel costs from fuel-switching, purchased power costs). Because allowances are so different from the other categories, the Commission believes they warrant their own account classification.

Classifying allowances into new accounts will enhance the usefulness of a utility's financial statements by readily providing users of those statements with information about allowances. Combining allowances in existing accounts developed for other assets would make full financial disclosure more difficult.

Classifying allowances in new accounts is also consistent with the goal of prescribing unbiased, "rate neutral" accounting. The commenters who argue against using new accounts suggest that account classification influences ratemaking. They propose classifying allowances in existing accounts for, e.g., fuel, in order to facilitate a desired ratemaking result. It is not the Commission's intention to dictate any particular ratemaking result through this accounting rule. The Commission's objective is to provide sound and uniform accounting that will accommodate whatever ratemaking treatment is ultimately found appropriate in each ratemaking jurisdiction.

The Commission does not believe that using new accounts would preclude rate recovery or cause utilities to incur unnecessary litigation costs in order to recover their allowance costs. The use of existing accounts could improperly permit utilities to recover allowance costs under automatic adjustment mechanisms or under pre-existing contracts without a regulatory determination that allowance costs should be recovered in such ways. The use of existing accounts may wrongly deny utilities, their customers and their regulators the opportunity to address the ratemaking treatment of allowances.[19]

Some commenters argue for account classification based on the ratemaking for each utility or the "economics" of the underlying transaction.[20] While the Commission agrees that accounting should accommodate the ratemaking process and reflect the economic substance of transac-

[18] S. Rep No. 621, 74th Cong., 1st Sess. (1935) (accompanying the bill which became Parts II and III of the Federal Power Act) states: "Section 301 [of the Federal Power Act] requires every licensee and every public utility subject to the act to keep its accounts in the manner prescribed by the Commission: it thus takes a long step in the direction of the uniform accounting which is so essential in the electric industry. The authority of the Commission over the accounts of companies under its jurisdiction extends to the entire business of such companies.

[19] Some commenters argue for the creation of an allowance recovery clause, like a fuel clause, that would transfer the costs and benefits from the sales and use of allowances to ratepayers. Others argue for and against fuel clause recovery. The Commission declines to address these arguments here because the scope of this rulemaking is limited to accounting issues.

[20] Virginia Power argues, for example, that allowances acquired in a package with high sulfur coal should be classified as a component of the cost of fuel, since they are an integral part of burning this particular coal. This argument, however, oversimplifies the analysis by ignoring other factors that also may affect a utility's CAAA compliance strategy. These other factors include the number of allowances already held by the utility, the degree to which the utility is controlling emissions (*e.g.*, with scrubbers), and the utility's intended use of the allowances (*e.g.*, for current or future year compliance or for speculation).

tions,[21] the accounting adopted in this final rule will accomplish these goals yet provide consistent and uniform accounting treatment of allowances. Also, separating allowance costs from the other costs of a transaction will offer easy access to useful information on allowances by utility managers, regulators and other readers of utility financial statements. Conversely, inconsistent account classification based on the particulars of each transaction would not provide the uniform accounting essential to the Commission's regulation of utilities[22] and would impede access to useful information on allowances.

The Commission rejects the argument that the relationship between allowances and power generation justifies classifying allowances as fuel. Fuel is not the only determinant of allowance usage. Utilities will use allowances based on their SO_2 emission levels. Emission levels, in turn, reflect a number of factors, including the use and effectiveness of a utility's pollution control equipment, its generating efficiency and mix at any given time and its load dispatching practices. Even if a direct relationship could be shown between the amount of fuel burned and the utility's emissions, the accounting result would necessarily be the same as that provided by the rule, *i.e.*, allowances would be charged to expense based on the amount of SO_2 emissions. The Commission sees no advantage, from an accounting standpoint, in classifying allowances as fuel.

On the other hand, the comments suggest that the major benefit to utilities in classifying allowances as fuel is that it will facilitate rate recovery of allowance costs (*e.g.*, through fuel adjustment clauses, account-specific formula rates, and other rate recovery mechanisms). However, as explained above, facilitating rate recovery is not a valid basis for classifying allowances in the fuel accounts.

Another issue raised by commenters is whether to use separate classifications for current and long-term allowances. They assert that allowances that will not be used during a utility's normal operating cycle (generally one year) are long-term assets, not current inventories. While the Commission generally agrees that some allowances may not be used during a utility's normal operating cycle and are therefore long-term in nature, the Commission does not find it necessary to create new accounts for separate classification of such allowances. Instead, the Commission will require that current and long-term allowances be classified separately on the balance sheet for reporting purposes only. Reclassification for reporting purposes will achieve the correct balance sheet categorization of non-current allowances without imposing additional accounting burdens on utilities.[23]

The Michigan Staff asks the Commission to require utilities to maintain Accounts 158.1 and 158.2 by affected generating unit. The Commission notes that although allowances are initially allocated based on the emission levels of specific generating units, allowances can be used for any unit owned or operated by the same person. The Commission does not perceive the merits of classifying allowances by affected generating unit and declines to require this approach. Nothing in this rule, however, would prohibit a utility from maintaining any additional level of detail deemed necessary in subsidiary records, including information on allowances by affected generating unit.

A number of commenters assert that the prescribed accounting must first be consistent with GAAP for non-regulated enterprises and then reflect the effects of regulation in accordance with Statement of Financial Accounting Standards No. 71 of the Financial Accounting Standards Board (FASB).[24] The Commission disagrees. To carry out its responsibilities

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[21] *See, e.g.*, Termination of Inquiry on Accounting for Phase-In Plans, *FERC Statutes and Regulations* ¶ 35,524, 57 FR 13064 (1992).

[22] *E.g.*, *id.* at n.1.

[23] Reclassification only for balance sheet purposes is not unique. The USofA already provides for reclassification at the balance sheet date for certain accounts. For example, *see* Account 164.1, Gas Stored Underground-Current, and paragraph A of Account 166, Advances for Gas Exploration, Development, and Production, 18 CFR Part 201 (1992). For allowances, the Commission is simply requiring use of the same account numbers for both current and non-current allowances.

[24] FASB, Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation* (1982), *in Accounting Statements—Original Pronouncements* (1991). Since 1973, the Securities and Exchange

under the Federal Power Act (FPA) and the Natural Gas Act (NGA), the Commission has been given authority to prescribe accounting and financial reporting requirements for jurisdictional companies.[25] The Commission, for ratemaking and other purposes, needs financial statements that allow it to determine the current cost of service and to monitor past performance under approved rates.[26] If GAAP conflicts with the accounting and financial reporting needed by the Commission to fulfill its statutory responsibilities, then GAAP must yield. GAAP cannot control when it would prevent the Commission from carrying out its duty to provide jurisdictional companies with the opportunity to earn a fair return on their investment and to protect ratepayers from excessive charges and discriminatory treatment.

Having said this, the Commission notes that its accounting rules are, with limited exceptions, consistent with GAAP.[27] Any exceptions are necessary, in the Commission's view, to provide for appropriate recognition of assets, liabilities and equity capital, and for proper matching of revenues and costs. The Commission's authority to prescribe the accounting needed or appropriate for regulatory purposes under the FPA and NGA is unambiguous. Thus, while the Commission believes the accounting prescribed in this rule is generally consistent with GAAP for non-regulated entities, any differences from GAAP are needed or appropriate in order for the Commission to fulfill its statutory duties. For these reasons, the Commission declines to explicitly adopt FASB pronouncements as requirements subsumed in the USofA, as some commenters seem to suggest.

A number of commenters urge the Commission to segregate allowances obtained for speculative purposes from those obtained for compliance purposes. Although the NOPR stated that speculative allowances should not affect inventory pricing since they do not relate to utility operations,[28] it did not propose separate account classification for such allowances. EEI and others recommend that speculative allowances be classified as investments in Account 124, Other Investments, with any gains or losses on disposition recorded "below-the-line."[29] The commenters assert that separate account classification is needed to avoid inappropriate costing of allowances used for compliance purposes and to distinguish speculative allowances for ratemaking purposes. The Commission agrees and will require that allowances obtained for speculative purposes be accounted for as investments in Account 124. Any costs or benefits incurred or realized through transactions involving speculative allowances, including gains or losses on disposition of such allowances, should be charged or credited to Account 421, Miscellaneous Nonoperating Income, or Account 426.5, Other Deductions, as appropriate. As with other aspects of this final rule, however, this accounting treatment would not be dispositive of the ratemaking treatment for such costs and expenses.

2. *Withheld Allowances*

As noted in the NOPR, section 416 of the CAAA requires EPA to withhold 2.8 percent of the annual allocation of allowances, for the purpose of sale or auction by EPA.[30] The Commission proposed that, since the utility cannot use these withheld allowances, they should be accounted for separately from other al-

(Footnote Continued)

Commission has recognized FASB as the designated organization in the private sector responsible for establishing accounting and reporting standards. FASB's purpose is to establish and improve standards of financial accounting and reporting for the guidance and education of the public, including issuers, auditors and users of financial information.

[25] *See* Sections 301, 302 and 304 of the FPA, 16 U.S.C. §§825, 825a and 825c (1988), and Sections 8, 9 and 10 of the NGA, 15 U.S.C §§717g, 717h and 717i (1988). *See also* 15 U.S.C. § 79t(b) (1988).

[26] *See* Notice of Inquiry on Accounting for Phase-In Plans, *FERC Statutes and Regulations* ¶ 35,521 at pp. 35,666-67, 53 FR 20496 (1988).

[27] *See* Statement of Policy on Post-Employment Benefits Other Than Pensions, 61 FERC ¶ 61,330 at p. 62,201 (1992).

[28] *FERC Statutes and Regulations* ¶ 32,481 at p. 32,579.

[29] "Below-the-line" accounts contain amounts that are not operating income or expenses and, therefore, are not generally included in rates.

[30] *FERC Statutes and Regulations* ¶ 32,481 at p. 32,582.

lowances in Account 158.2, Allowances Withheld.

Comments: NARUC, the Florida Commission and the Georgia Commission support the NOPR's proposed accounting treatment. The Ohio Staff also agrees with using a separate account for withheld allowances.

AICPA, Deloitte & Touche, Price Waterhouse and Gulf States oppose the creation of Account 158.2. AICPA argues that the account would add recordkeeping and reporting requirements but may not improve the usefulness of the information provided. Price Waterhouse argues that the distinction between this account and Account 158.1, Allowance Inventory, is not important enough to warrant separate accounts and that any needed information can be obtained from the proposed reporting requirements.

Commission Response. The Commission believes that Account 158.2 is needed to distinguish between allowances that are eligible for the utility's use and those that are not. Allowances withheld by EPA may never be available for the utility's use[31] and should not be included with allowances that are available for use. Also, only those allowances available for the utility's use should enter into the determination of the weighted average cost of allowances used during a period. In the Commission's view, the minimum amount of recordkeeping needed to maintain a separate account for withheld allowances is worth the benefits of improved information and the simplification of monthly computations of allowance inventory cost.

3. *Existing Contracts*

Since the NOPR proposed to create new accounts for allowances, the Commission invited comments on whether and, if so, how the proposed regulations should apply to existing contracts expressly based on the existing accounts in the USofA, *e.g.*, account-specific cost-of-service formula rates or joint operating agreements.[32]

Comments. NARUC and the Florida Commission support application of the final rule to such contracts, arguing that contractual relationships should not dictate the accounting requirements of the USofA. The Michigan Staff agrees, stating that existing contracts should be amended to reflect the costs and benefits realized from allowances.

The NC Municipal Agency argues that the final rule should not affect the determination of rate matters under existing agreements. The Agency argues that attempting to apply this rule to existing account-specific contracts would likely pose a substantial risk of unpredictable and improper outcomes, including the risk of disturbing the economic balance underlying existing formulas or agreements. The Agency argues that, if the final rule applies to existing contracts, and the Commission decides to account for allowances by revising accounts already included in existing agreements, the Commission should state that its revision of those accounts will "reopen" all affected rate agreements. If this were done, the Agency argues, the affected parties could then reaffirm or renegotiate their arrangements or, if needed, seek a Commission resolution of disputed issues.

NRECA argues that the final rules should not apply automatically to existing contracts with account-specific rates. NRECA argues that to do so would be tantamount to retroactive ratemaking.

The Georgia Commission argues that, for existing wholesale formula rates, the Commission could mandate a cost recovery framework allowing recovery of costs recorded in new accounts that would have been included in the formula if the accounts existed when the contracts were executed. The Georgia Commission argues that, otherwise, these contracts will need to be modified.

Several commenters recommend avoiding complications with existing contracts by classifying allowances in existing accounts, instead of new accounts. AEP argues that, in order for utilities to recover allowance costs under existing account-specific formula rates without renegotia-

[31] Withheld allowances will be offered by EPA for sale or auction. Any allowances not sold or auctioned will revert to the utility from which they were withheld. When such allowances become available for the utility's use, they should be transferred to Account 158.1.

[32] *FERC Statutes and Regulations* ¶ 32,481 at p. 32,576

tions or litigation, allowances should be classified in existing accounts based on the ratemaking adopted for each utility. Atlantic Electric and Gulf States ask the Commission to use existing accounts in prescribing a cost recovery framework for existing formula rates. PSI Energy asserts that, to ease the transition for companies with existing account-specific contracts, allowances should be recorded in subaccounts of existing accounts. If the Commission uses new accounts, AEP and Gulf States ask the Commission to automatically amend existing Commission-approved contracts.

If new accounts are used for allowances, EEI, Duke Power, PSI Energy, Southern Company and Virginia Power argue that, for existing contracts intended to recover system average costs, the Commission should specify that the return of and return on the prudently incurred costs of complying with the CAAA should be included in the determination of costs to be recovered, even though the costs are recorded in new accounts not listed in the contracts. EEI and Southern Company assert that, when pricing mechanisms are intended to recover the cost of specific units instead of system average costs, the final rule should allow economic value to be charged in appropriate instances.

The Ohio Staff recommends that the parties to existing contracts should be required to keep sufficient information on allowance trades so that when an order is issued, amounts can be reclassified in the new accounts.

Commission Response. As an initial matter, the Commission holds that allowance-related costs should be accounted for as prescribed in this rule even if service is provided under an existing contract. In light of the need for accounting uniformity and consistency, the fact that service is being provided under existing contracts does not warrant an exception from this rule.

The more fundamental issue raised by the commenters is whether the Commission, in this rulemaking, should seek to resolve all uncertainty on the ratemaking for such costs under existing contracts. The Commission believes that issuing an edict in this rulemaking on the recovery of allowance costs under existing contracts would not be in the public interest. Trying to resolve all uncertainty about ratemaking for allowance costs under existing contracts would contravene the Commission's "rate neutrality" intent and, on the record here, would likely generate considerable confusion. If the Commission in this proceeding were to order the automatic inclusion of allowance costs in existing contracts, there could be unintended effects on cost determinations and responsibilities under existing contracts. At least at this time, the better course is for affected parties, if necessary, to renegotiate their contracts to provide for a consensual treatment of the costs and benefits of allowances, and to file such changes pursuant to Part 35 of the Commission's regulations.

C. *Valuation of Allowances*

1. *General Rule—Historical Cost*

The Commission proposed in the NOPR to measure the value of allowances, as a general rule, based on historical cost.[33] The NOPR defined historical cost as the amount of cash or its equivalent paid to acquire an asset, *i.e.*, its historical exchange price. Under this approach, allowances obtained from EPA at no cost to the recipient would be recorded at zero cost, while purchased allowances would be recorded at their historical exchange price.

Support for the NOPR. Many commenters support the use of historical cost.[34] The Department of Energy states, for example, that historical cost satisfies accounting disclosure needs, yet allows for independent ratemaking treatment for allowances. APPA asserts that any cost basis other than historical cost may lead to miscalculation of rate base. APPA argues that recording allowances at fair value could unjustifiably overstate a utility's assets and operating expenses. The American Gas Association states that historical cost is appropriate for valuing all allowances and is consistent with valua-

[33] *FERC Statutes and Regulations* ¶ 32,481 at pp. 32,576-77.

[34] Department of Energy, NARUC, the Florida Commission, the Georgia Commission, the Illinois Commission, AICPA, Arthur Andersen, Baltimore Gas & Electric, Centerior, Central & South West, Con Edison, Delmarva Power, Gulf States, Virginia Power, Wisconsin Electric, Wisconsin Public Service, APPA and the American Gas Association.

tions used for most other regulated assets, including inventory.

Wisconsin Public Service states that using measures other than historical cost would raise verification issues because the allowance market is unlikely to be highly developed by the time allowances must be initially recorded. Wisconsin Public Service asserts that other measures would likely require utilities to record significant assets and offsetting regulatory liabilities. Wisconsin Public Service asserts that the confusion caused by recording large assets and offsetting liabilities for allowances would outweigh any benefits derived.

Deloitte & Touche supports the use of historical cost for allowances awarded by EPA at zero-cost, stating that this approach is consistent with GAAP. Deloitte & Touche also states, however, that these allowances will have significant economic value, based on the market price for traded allowances. Deloitte & Touche asserts that using historical cost for a valuable economic asset such as zero-cost allowances might not present users of financial statements and regulators with useful and relevant financial information Thus, Deloitte & Touche urges the Commission to undertake a study of this issue.

Decline in Value of Allowances GPU argues that if historical cost is used, the final rule should address the issue of market value declines. GPU proposes that the excess of cost over market which is deemed significant and permanent should not be written off to the income statement, but should remain on the balance sheet and be expensed when charged to ratepayers in the ratemaking process or determined to be uncollectible.

Atlantic Electric asserts that technological advances could reduce the value of allowances held in inventory and argues that this event should be given accounting recognition. Atlantic Electric believes that the accounting should reflect the "lower of cost or market."

Allowances From Overcompliance. The Ohio Staff asserts that the NOPR did not adequately address the accounting for allowances freed up by overcompliance, *i.e.*, whether the cost of overcompliance should be reflected in the cost of allowances. The Ohio Staff asks: what is the cost of allowances freed up by overcompliance; how should the costs be determined; and where should these allowances be recorded?

Indirect Costs. The Ohio Staff suggests that the cost of purchased allowances should include costs directly related to purchasing specific allowances. The Ohio Staff asserts that costs not directly related to purchasing specific allowances should be expensed in the period in which they are incurred. Similarly, Atlantic Electric asserts that certain "handling" and administrative costs incurred in acquiring allowances should be included in allowance costs. Pennsylvania Power & Light asserts that allowance costs should include the costs of acquiring, maintaining and disposing of allowances, *e.g.*, broker fees, incentive bonuses and selling commissions.

Fair Value. AEP supports using fair value instead of historical cost when doing so is needed to allocate compliance costs equitably to all ratepayers. AEP agrees with using historical cost for purchased allowances but argues that using this method for allowances allocated by EPA at zero cost may send the wrong signal to regulators, *i.e.*, that allocated allowances always should be valued at zero. AEP asserts that this approach, if used for ratemaking, could distribute compliance costs inequitably between ratepayers and could discourage allowance trades between affiliates in least cost compliance strategies and among non-affiliates in a power pool.

AEP asserts that using historical cost for allocated allowances is contrary to Accounting Principles Board (APB) Opinion No. 29[35] and a recent FASB exposure draft on accounting for contributions.[36] According to AEP, both documents support the use of fair value in accounting

[35] FASB, Accounting Principles Board Opinion No. 29, *Accounting for Nonmonetary Transactions, in Accounting Standards Original Pronouncements* (1991).

[36] FASB Exposure Draft on *Accounting for Contributions Received and Contributions Made and Capitalization of Works of Art, Historical Treasures and Similar Assets,* File Reference No. 096-B (October 1990).

for assets received in nonmonetary transactions.

Coopers & Lybrand argues that allocated allowances should initially be recorded at current market value, with credits to operating expenses, and thereafter "marked to market."[37] Coopers & Lybrand agrees with recording purchased allowances at cost, but proposes that they also be later "marked to market," *i.e.*, valued at current market price. Coopers & Lybrand asserts that this method would prevent utilities from recognizing the gain on sale of unused allocated allowances, accumulated over time, entirely in the period of the sale. Coopers & Lybrand argues that this method also provides the most relevant information about the utility's available allowances at each reporting date and about gains and losses incurred during the reporting period. Coopers & Lybrand states that the "marked to market" method depends upon the development of a market which will allow fair value to be determined within reasonable limits.

Rate Considerations. EEI agrees with using historical cost for purchased allowances and states that most EEI members agree that allowances allocated by EPA at no cost should be recorded at zero cost. EEI and others[38] argue, however, that the economic value of allowances should be reflected in the pricing of allowances used in sales for resale and in the operation of power pools. EEI asserts that utilities should be allowed to recover a fair share of the cost from wholesale customers in order to properly compensate retail customers, many of whom will face rate increases to pay for scrubbers or low sulfur coal. EEI argues that this is particularly important for allowances allocated by EPA at zero cost. EEI states that, while these ratemaking issues may be deemed beyond the scope of this rulemaking, the Commission should at least discuss this generally so that utilities will know the likely results as they choose compliance strategies.

Commission Response. The great majority of the commenters generally favored using historical cost for both allocated allowances and purchased allowances. For the reasons given in the NOPR and those cited by the commenters, the Commission believes that historical cost is the appropriate measure of the accounting value of allowances. Historical cost is the primary measurement attribute used in the USofA, as well as GAAP, for recording intangibles and most other utility assets.[39] Historical cost also is readily ascertainable, verifiable and free from bias, and provides useful information to regulators, investors and other users of a utility's financial statements. The characteristics of historical cost make it especially appropriate for use in regulatory accounting.

The use of historical cost for accounting purposes, however, is not intended to control or prejudge the ratemaking valuation of allowances. The Commission's determination in this rule applies only to the accounting for allowances.

To the extent that using historical cost for a valuable economic asset such as zero-cost allowances is perceived as limiting the usefulness and relevance of utility financial statements, utilities can alleviate this concern by disclosing the economic value of allowances in the footnotes to their financial statements. This final rule allows, but does not require, disclosure of such information in this way, if utility management considers disclosure desirable.

Certain commenters supported valuing allowance inventories at the "lower of cost or market," *i.e.*, requiring utilities to write-down their allowance inventories to net realizable value to reflect permanent changes in the value of allowances. The Commission declines to adopt this recommendation. At least in the near term, the

[37] Coopers & Lybrand actually applies its recommendation only to "excess" allowances, *i.e.*, allowances allocated in a given year but not needed to offset the recipient's emissions in that year. Coopers & Lybrand argues that no accounting recognition is needed for allowances used to offset emissions in the year in which the allowances are allocated.

[38] Allegheny Power, Iowa-Illinois, PacifiCorp, PJM and Wisconsin Public Service.

[39] "Historical cost" should not be confused with "original cost." Original cost, when used in connection with plant, is the cost to the first person devoting the property to public service. Historical cost is the acquisition cost of assets. The historical cost of purchased plant for a public utility would be the sum of the original cost and any related acquisition adjustments. *See* 18 CFR Parts 101 and 201, Account 114, Plant Acquisition Adjustments.

historical cost of allowance inventories will be less than market value for most utilities, due to combining zero-cost allowances with the cost of purchased allowances in the inventory pool. However, even if the historical cost of allowances were to exceed market value, it does not necessarily follow that rates would be set on a basis less than historical costs. Thus, at least for now, any need for writing down allowance inventories will be decided case-by-case. If an asset is impaired, and rate recovery is not assured, the write-off should be recorded in Account 426.5, Other Deductions.

Several commenters assert that the accounting valuation of allowances should include costs directly related to purchasing specific allowances, *e.g.*, broker fees and selling commissions. The Commission believes that significant, directly-assignable acquisition costs should be included in the historical cost of the allowances. In theory perhaps all indirect costs of acquiring inventory should be added to the inventory's purchase price. However, the effort involved in identifying and allocating relatively small amounts of indirect costs would probably exceed the benefits derived from more precise costing. Also, such allocations would probably involve the use of arbitrary assumptions and make compliance determinations more controversial and not necessarily more accurate. Thus, the Commission will limit the inclusion of such costs to significant, directly-assignable costs of acquiring allowances. Other costs incident to acquiring allowances should be charged to an appropriate functional expense account when incurred.

The Ohio Staff asks whether the cost of freeing up allowances by overcomplying, *e.g.*, installing scrubbers or switching fuels, should be reflected in the historical cost of allowances. The answer is no.[40] The cost of allowances should include only the historical cost of acquiring the allowances themselves, not the additional costs incurred for overcompliance. Although compliance costs may relate indirectly to allowances, *e.g.*, by "freeing up" allowances or affecting a utility's decision to buy allowances or the price a utility is willing to pay for allowances, overcompliance costs are not part of the cost of the allowances themselves.[41] Because the money spent for overcompliance relates most directly to the item(s) acquired, *e.g.*, the scrubber or the higher cost fuel, the cost of overcompliance should be accounted for in the cost of the item acquired. There is no need, from an accounting perspective, to assign any part of the cost of overcompliance to allowances.

AEP asserts that using historical cost for allowances allocated by EPA is contrary to APB Opinion No. 29 and a FASB exposure draft on accounting for contributions.[42] The Commission does not believe that allocated allowances are within the scope of the FASB exposure draft, since the draft applies only to voluntary transfers, while EPA has a statutory duty to transfer the allocated allowances as prescribed by the CAAA. Moreover, the exposure draft cited by AEP, as since revised and re-proposed by FASB, would not apply to "transfers of assets from governmental units to business enterprises," an exemption which appears to apply to allowances.[43] But, even if allowances are within the scope of APB Opinion No. 29 or the FASB exposure draft, the Commission believes for the reasons stated above

[40] *See FERC Statutes and Regulations* ¶ 32,481 at p. 32,577 n.38 ("The cost of any such [compliance] investments or expenditures would be accounted for independent of the allowances obtained as a result of such investments or expenditures, in the accounts already established for such costs in the USofA.")

[41] For example, if a utility paid $500 for an allowance, its historical cost would be $500. Installing a scrubber in order to "free up" this allowance would not increase the cost of the allowance itself. Although overcompliance may add to the utility's options, *e.g.*, to sell the allowance or save it for future needs, overcompliance does not affect the cost of the allowance itself.

[42] The Commission notes that AICPA, in its comments, disagrees with AEP's interpretation of APB Opinion No. 29. According to AICPA, allowances do not qualify as nonreciprocal transfers eligible for fair value accounting treatment under APB Opinion No. 29 because the CAAA impose a reciprocal obligation on utilities to limit their sulfur dioxide emissions.

[43] FASB Exposure Draft on *Accounting for Contributions Received and Contributions Made*, File Reference No. 121-A at 2 (November 1992).

that general GAAP is not controlling in this proceeding.

Coopers & Lybrand argues that "excess" allocated allowances, *i.e.*, those not needed for current year emissions, should be recorded at fair value and later "marked-to-market." The Commission declines to adopt this recommendation in this accounting rule as not needed for sound accounting. Coopers & Lybrand's method differs from the historical cost method solely in the timing of the recognition of compliance costs and gains and losses on disposition of allowances. If compliance costs and gains or losses are recognized in different periods for ratemaking purposes than for accounting purposes, the provisions on regulatory assets and liabilities adopted below will capture the economic effects of such rate actions.

Finally, the Commission rejects the argument that fair value should be used for accounting purposes in order to facilitate the use of fair value for ratemaking purposes. If fair value is used for allowances in ratemaking but not in accounting, the rule adopted herein can accommodate this result through the recognition of regulatory assets and liabilities. In any event, prescribing or prejudging the ratemaking treatment for allowances is beyond the scope of this accounting rulemaking. In conclusion, for all the reasons stated above, the Commission adopts the use of historical cost as the accounting measure of allowances.

2. *Cost Allocation for Package Purchases*

For allowances obtained in a package with other commodities, *e.g.*, fuel or electricity, the NOPR proposed to determine the historical cost of the allowances based on their fair market value at the time of purchase.[44] The NOPR also proposed to allocate the purchase price for a stream of allowances on the basis of fair value or, if fair value cannot be determined, on a present value basis using a discount rate based on the rate on ten-year U.S. Government bonds, *i.e.*, a risk-free interest rate.

Allowances Acquired as Part of a Package. NARUC, the Florida Commission and the Georgia Commission support the use of fair value in determining the historical cost of allowances obtained as part of a package. NARUC, Delmarva Power and the Michigan Staff also suggest an optional method based on allocating the package's historical cost in proportion to the ratio of each item's fair market value to that of all items. In support, the Michigan Staff argues that using fair value only for the allowance part of the package may distort the cost allocation.

Cincinnati Gas & Electric opposes the adoption of a mandatory valuation method for determining the value of allowances obtained in a package. Cincinnati Gas & Electric asserts that the value of allowances should be determined in each case based on the facts and circumstances of the case.

Stream of Allowances. The Ohio Staff agrees with the proposed method of allocating costs for a stream of allowances. Allegheny Power states that, if fair value cannot be determined for a stream of allowances, the present value method is an acceptable method unless the contract specifies a different cost allocation.

EEI and others[45] argue that the Commission should not prescribe present value or any other method as the sole alternative to fair value. EEI argues that, if fair value cannot be determined, the facts and circumstances of each trade should be reviewed to determine which method most accurately allocates the cost of individual allowances in a stream of allowances. EEI also states that FASB has begun an inquiry into present value accounting and argues that it would be premature to adopt a present value approach until FASB's inquiry is completed. PSI Energy argues that, without market data, and because there have been no trades to determine reasonable methods for allocating future costs, mandating a single method may be inappropriate.

Atlantic Electric asserts that, if the use of present value is required, the final rule should describe how to account for the difference between the purchase price and the present value.

The discount rate. AICPA argues that using a risk-free interest rate in a present value analysis ignores significant market

[44] *FERC Statutes and Regulations* ¶ 32,481 at pp. 32,577-78.

[45] Atlantic Electric, Commonwealth Edison, Con Edison, Detroit Edison, PSI Energy, Virginia Power and Wisconsin Electric.

and interest-rate risks. AICPA contends instead that utilities should be required to use any interest rate that properly reflects prevailing risk (*e.g.*, the incremental borrowing rate). Price Waterhouse argues that a company-specific incremental rate should be used when prescribed by GAAP. Arthur Andersen supports using the utility's incremental borrowing rate or its authorized rate of return as the discount rate.

EEI and Allegheny Power assert that the discount rate should correspond to the time period of the stream of allowances and propose using a company's incremental borrowing rate for the applicable years. EEI argues that this is the discount rate used in other present value calculations under FASB Statement No. 13[46] and is more relevant to the circumstances of each utility.

PSI Energy and Deloitte & Touche argue that utilities should be allowed more flexibility in determining the discount rate. PSI Energy argues that participating in the allowance trading market will pose risks and that these risks will not be properly reflected in a risk-free interest rate. PSI Energy also states that using a risk-free rate would conflict with the discounting theory used in making financial decisions.

Detroit Edison supports using a discount rate based on Moody's Long-Term A grade bond yield or a similar average yield. Detroit Edison agrees that using a rate that achieves uniformity and comparability among public utilities is beneficial but opposes the use of a risk-free rate.

Commission Response. The use of fair value in determining the historical cost of allowances acquired as part of a "package" was supported by most of those who commented on this aspect of the NOPR. The Commission finds this approach appropriate and, with the clarifications below, will adopt the use of fair value as the measure of allowances acquired as part of a "package."

The NOPR proposed to determine the historical cost of allowances acquired as part of a package based on the fair market value of only the allowances. NARUC and others suggest an optional method using the ratio of the allowances' fair market value to the total fair market value of all elements of the package. The fair market value of allowances could be determined in at least three ways: by comparing the price of the "package" with and without the allowances; by direct reference to market prices; and by use of the ratios suggested by NARUC. Of the three, direct reference to market prices will be most readily determinable and easiest to verify. This method would be easier for utilities to use and regulators to verify than a ratio-based method, since the former focuses on the fair value of only the allowances and the latter addresses the fair value of all components of a package. Moreover, these two methods would produce the same result in most cases, differing only in the presumably infrequent case in which the transfer price differs from the sum of the fair market values of all components of the package. In the more likely case in which the transfer price equals the sum of the fair market values, a ratio-based approach would lead to unnecessary effort in documenting the fair value of non-allowance components of package trades and unduly complicate the determination of allowance values. Thus, the Commission declines to require the use of a ratio-based method in all cases. Instead, the Commission will adopt the NOPR's method as the primary method. However, if reliable market prices for allowances are not available, or if the sum of the fair market values for all parts of the package is determined and does not equal the transfer price, then an alternative method may be used. In such a circumstance, the utility proposing to use an alternative method will be required to make a sufficient showing in support of its decision to use an alternative method.

Several commenters objected to the required use of present value when fair value cannot be determined, instead recommending the use of contractually-specified amounts or amounts determined based on the circumstances of each case. The Commission disagrees. A primary objective of this rule is to provide uniform accounting for allowances. Permitting utilities unlimited discretion in choosing the method for valuing allowances would be contrary to that objective. The Com-

[46] FASB, Statement of Financial Accounting Standards No 13, *Accounting for Leases* (1976), *in Accounting Statements Original Pronouncements* (1991).

mission believes that, in the absence of fair value, it is necessary to prescribe a uniform method that is both objective and reflective of the value of allowances on the date of their acquisition.[47] The present value approach reasonably achieves these goals, is rational and systematic and reflects the higher value of an allowance usable today compared to one usable only in the future. Although other measures may be more precise in particular circumstances, the gain in objectivity and uniformity more than offsets any possible loss in precision. Therefore, the Commission will limit the measure of the historical cost of allowances acquired as part of a package to present value, if fair value is not determinable.

A number of commenters challenge the proposed use of the interest rate on ten-year U.S. Government bonds in present value determinations. They argue that utilities should be allowed to use a rate that better reflects the risks involved in trading allowances as well as each utility's particular circumstances. They also assert that the discount rate should correspond to the time period of the stream of allowances. The Commission finds merit in these arguments. Accordingly, the final rule will provide for the use of the utility's incremental borrowing rate instead of the interest rate on ten-year U.S. Government bonds.[48] Incremental borrowing rates, while not as objective as government bond rates, will correspond more closely to the rate utilities will use in considering allowance purchases and will better allocate the cost of the purchases. Incremental borrowing rates also are widely accepted by the accounting profession and used in a number of present value determinations, including the valuation of receivables and payables, leases, and plant abandonments.

Prescribing the use of present value at this time is not premature even though FASB is still conducting an inquiry on present value measurement. The FASB inquiry relates to whether discounted present value should be used as the measure of assets and liabilities that will be realized through future receipts or payments. In contrast, the Commission is simply prescribing the use of present value as a technique for allocating the actual historical cost of a purchase among allowances of different vintages.[49] Therefore, the present value measurement adopted in this rule is different from the determination at issue in the FASB inquiry.

3. *Allowance Trades Between Affiliates*

The NOPR proposed that a company obtaining allowances from an affiliate should record as its cost the inventory cost of the affiliate that first obtained the allowances.[50] The NOPR stated that any difference between this cost and the sale price should be recognized as an equity contribution between affiliates and recorded in Account 211, Miscellaneous Paid-in Capital.

Comments. NARUC, the Florida Commission and the Georgia Commission support the Commission's proposal, so long as records allow state regulators to determine the proper ratemaking treatment.

EEI and others[51] argue that allowances traded between affiliates should be valued at fair value. These commenters raise many different arguments. For example, EEI and certain others[52] argue that the proposed rule would discourage affiliate trades, contrary to the decision by Congress to exempt allowance trades from the jurisdiction of the Securities and Ex-

[47] When contractual values approximate fair market value, they may be used as the measure of fair market value. Only in the absence of fair value must present value be used.

[48] The incremental borrowing rate is the interest rate that, at the time of the allowance acquisition, the utility would have incurred to borrow sufficient additional funds to purchase the allowance(s) for the amount of time the utility expects to hold the allowances.

[49] Atlantic Electric asks how to account for the difference between the purchase amount and the present value. There will not be a difference, however, since the present value calculation merely allocates the total purchase amount among the acquired assets by vintage.

[50] *FERC Statutes and Regulations* ¶ 32,481 at p. 32,578.

[51] Coopers & Lybrand, Price Waterhouse, Chicago Board of Trade, Allegheny Power, Atlantic Electric, Central & South West, Con Edison, Consumers Power, the Iowa Working Group, GPU, Gulf States, IES Industries, Kentucky Utilities, NRECA, PacifiCorp and Virginia Power.

[52] Allegheny Power, Atlantic Electric, AEP, Central & South West and Southern Company.

change Commission (SEC).[53] Southern Company and AEP argue that the proposed accounting would undo the Congressional intent to allow affiliates to transfer allowances on a basis other than cost.

Allegheny Power asserts that affiliate trades are scrutinized by the Commission, various state commissions, internal and external auditing groups, and the SEC. Allegheny Power argues that trades at less than fair value would raise prudence questions.

Allegheny Power asserts that open market trading by affiliates would be more costly, less efficient and possibly less reliable than intra-system trading. Similarly, EEI argues that affiliates trading on the open market would incur unnecessary transaction costs. EEI and Centerior argue that the proposed rule would impair the ability of affiliated utilities to engage in least cost compliance planning. Southern Company argues that if affiliates cannot transfer allowances between themselves at fair value, they may not be able to maintain allowance reserves on a system-wide basis and might increase the number of allowances that each utility holds.

PacifiCorp asserts that, unless fair value is used for affiliate trades, full cost recovery is not possible and the allowance market will not develop. The Illinois Commission argues that the proposed accounting, by discouraging affiliate allowance trades, may impede the establishment of an active allowance market.

The Chicago Board of Trade argues that using current market value would properly make affiliates indifferent between trading on the open market or with an affiliate. The Board argues that using a valuation method other than market value could encourage affiliates to trade with each other on a non-competitive basis instead of on the open market. The Board asserts that affiliate trades deprive other interested parties of the public price signals needed to help minimize compliance costs.

The Iowa Working Group argues that the NOPR's proposed accounting could lead to cross-subsidization within multistate companies. The Group asserts that, *in seeking least cost compliance, holding* companies or affiliated utilities may overcontrol emissions at one company's unit to avoid making reductions at another company's unit. The Group states that, when the allowances freed up by overcontrol are transferred from the first company to the second one, the use of zero-cost accounting could result in the first company subsidizing the second one.

The Group also argues that the proposed accounting may lead to cross-subsidization between a holding company's regulated and unregulated operations. The Group states that, under the NOPR's proposed accounting, a holding company could transfer allowances at zero-cost from a regulated company to an unregulated affiliate. The Group asserts that the unregulated affiliate could realize below-the-line profits by selling such allowances.

AICPA, Coopers & Lybrand and Deloitte & Touche argue that using original cost for allowances acquired from affiliates is inconsistent with GAAP, which, according to AICPA, usually does not distinguish between assets acquired from affiliates and those acquired externally in similar trades. AICPA asserts that the Commission should use its enforcement powers to determine the appropriateness of affiliate trades.

The Environmental Defense Fund, Centerior, Ohio Edison and Penn Power argue that affiliate trades should be treated the same as non-affiliate trades, *i.e.*, an allowance obtained from an affiliate should be valued at the sale price, not the seller's original cost. The Environmental Defense Fund asserts that the oversight of state regulators, especially if trades are between affiliates in two different states, should assure that prices reflect market value.

APPA states that fair market value could be used for affiliate trades if proper reporting measures assure that the market is disciplined by full and timely disclosure of market price information. APPA argues that if detailed information, including price and terms, is not available on all allowance trades, affiliates should be required to transfer allowances at historical cost.

[53] *See* Section 403(j) of the CAAA, 42 U.S.C. § 7651b(j).

NYDPS supports using historical cost for trades between an unregulated entity and an affiliated regulated utility, but supports using fair value for trades between two affiliated regulated utilities. NYDPS argues that trades between affiliated regulated utilities, unlike trades involving an unregulated affiliate, are subject to adequate state and federal oversight and present less risk of manipulation, since regulators will likely allocate any profit transfers to ratepayers' benefit. If fair value is used for trades between regulated affiliates, NYDPS proposes that a discount (*e.g.*, five to ten percent of market value) be applied to the derived market value, to recognize economies resulting from avoiding market transaction costs.

NRECA asks the Commission to clarify that the term "affiliate" is being used in the corporate legal sense and does not include entities whose only relationship is that of co-owners of a generating plant.

Commission Response. The great majority of commenters disagree with the NOPR's proposed accounting for affiliated transactions. These commenters argue that the proposed accounting may: discourage affiliate trades; unnecessarily raise the cost of acquiring allowances; impair system-wide least cost planning; raise prudence questions even when parties have acted prudently; provide misleading price signals to the allowance market; result in cross-subsidization between affiliates; and conflict with GAAP.

The Commission finds these arguments persuasive and, as explained below, has decided not to adopt the proposed accounting for affiliate transactions. The Commission believes that the cited deficiencies can be avoided by requiring the same accounting for affiliate transactions as for non-affiliate transactions. Thus, the Commission will require that all allowance transactions, including transactions with affiliates, be accounted for in the same manner, *i.e.*, the purchase price (historical cost) of an allowance will be the attribute used for accounting valuation regardless of whether the allowance is purchased from an affiliate or non-affiliate.

However, since affiliate transactions are by definition less than arm's length, the Commission will require certain additional safeguards for allowance transactions between affiliates. As support for accounting entries used to record purchases from and sales to affiliates, the Commission will require the transacting utilities to maintain enough information to allow ready identification, analysis, and verification of the market value of allowances at the time of the transaction, as well as other relevant information supporting the reasonableness of the exchange price.[54] The burden of proving the fairness of any value assigned to the allowances will rest with both the selling and purchasing utility. These safeguards, along with safeguards inherent in existing accounting practices (*e.g.*, consolidated income statements for affiliates) and in ratemaking prudence reviews, should prevent abusive affiliate trades intended to inflate assets or improperly benefit shareholders.

NYDPS proposes the application of a Commission-determined discount to the market value of allowances acquired from affiliates, to recognize economies resulting from avoiding market transaction costs. The Commission finds this refinement unnecessary. As explained above, the final rule allows the inclusion of market transaction costs in the historical cost of allowances. If savings in market transaction costs are achieved by trading with affiliates, the Commission believes the book cost of the allowances should reflect such savings. However, sufficient information on market transaction costs for non-affiliate trades should be obtainable without the need to establish an arbitrary percentage at this time. The Commission has adequate authority to correct any abuses that may occur in this regard.

In response to NRECA's request for clarification of the term "affiliate," the Commission intends the term to mean companies or persons that directly, or indirectly through one or more intermediaries, control, or are controlled by, or are under common control with, the accounting company. This is the same

[54] If the allowance market is not highly active, a range indicative of the current market value could be inferred from the prior and subsequent transaction prices that are available.

definition contained in Definition 5 of the USofA.[55]

4. *Allowance Futures*

In the NOPR, the Commission distinguished between hedge transactions and speculative transactions and proposed to treat a trade as a hedge transaction only when the utility, at the time it entered into a futures contract, designated the transaction in contemporaneous documents as one entered into for hedging purposes.[56] The Commission proposed to defer the costs or benefits of hedging transactions in Account 186, Miscellaneous Deferred Debits, or Account 253, Other Deferred Credits, and to include such amounts in Account 158.1, Allowance Inventory, when the related allowances were acquired, sold or otherwise disposed of. The Commission proposed to record the costs or benefits of speculative transactions in Account 421, Miscellaneous Nonoperating Income, or Account 426.5, Other Deductions.

Comments. EPA supports the inclusion of accounting rules for allowance futures, stating that the rules will facilitate utilities' use of allowance futures to manage risk associated with the allowance market.

NARUC, the Florida Commission, the Georgia Commission, the Illinois Commission and APPA support the proposed accounting treatment for allowance futures. NARUC proposes extending the same rules to "forward contract" trades outside of the organized exchanges, while the New York Mercantile Exchange proposes extending the rules to energy futures and options (*e.g.*, on crude oil and natural gas). The Ohio Staff agrees with the proposal to defer costs or benefits from hedging trades and include such amounts in inventory when the allowances are acquired, sold or otherwise disposed of. NRECA emphasizes that allowances held for investment purposes should be segregated in a separate account from allowance inventory held for operating purposes.

AICPA, Arthur Andersen, Deloitte & Touche and Price Waterhouse generally support the NOPR's proposal but assert that the deferred amounts should be recorded in the allowance accounts, not in Accounts 186 and 253. AICPA argues that deferral in the allowance accounts comports with FASB Statement No. 80.[57] Coopers & Lybrand argues that the proposed accounting for futures contracts should be replaced by a reference to FASB Statement No. 80.

Similarly, EEI and others[58] cite FASB Statement No. 80 and argue that the costs or benefits of hedging transactions should be included in inventory as the costs or benefits occur, and not deferred until the transaction is complete. In support, Atlantic Electric asserts that this approach would allow the average price of allowances in inventory to reflect hedging costs regardless of when specific allowances are included in inventory. Atlantic Electric questions whether the NOPR's proposed accounting conforms to the accounting for hedging of other assets, *e.g.*, fuel supplies.

The Wisconsin Municipal Group asserts that the proposed accounting could cause ratepayers to bear the risk of a hedging trade by paying a return on allowances included in rate base, while shareholders would receive any gain on the trade. The Group asserts that this could occur because the gain or loss on a hedging trade would be recorded in below-the-line Accounts 421 and 426.5, while the allowances would be recorded in Accounts 158.1 or 158.2 and might be included in rate base. The Group asserts that a procedure should be adopted for allowances used in hedging trades to ensure that these allowances will not be included in rate base.

The California Commission asserts that all costs of both hedging and speculation should be recorded in a non-operating subaccount of Account 421. The California Commission argues that distinguishing hedging from speculation would be

[55] 18 CFR Part 101, Definition No 5.

[56] *FERC Statutes and Regulations* ¶ 32,481 at pp. 32,578-79.

[57] FASB Statement of Financial Accounting Standards No. 80, *Accounting for Futures Contracts*, ¶ 6, *in Accounting Statements—Original Pronouncements* (1991).

[58] AEP, Atlantic Electric, Baltimore Gas & Electric, Centerior, Cincinnati Gas & Electric, Commonwealth Edison, Delmarva Power, Gulf States, Pennsylvania Power & Light and PSI Energy.

neither feasible nor purposeful. Instead, the California Commission argues, the proposed accounting would further burden the regulatory process by requiring regulators to evaluate a utility's designation of a trade as either hedging or speculation, to ensure that the utility is only passing on reasonably incurred costs and not siphoning off gains that should be used to reduce its revenue requirement. The California Commission argues that its proposal would discourage utilities from playing in the futures market and avoid unnecessary accounting and regulatory complexities.

Detroit Edison argues that utilities should not be required to designate a transaction as one entered into for hedging purposes. Detroit Edison asserts that utilities should be presumed to enter into futures contracts for the purpose of hedging rather than speculating.

AICPA and others[59] argue that allowances purchased for speculative purposes should be recorded in Account 124, Other Investments. EEI, Atlantic Electric, Commonwealth Edison and Florida Power & Light also assert that any gains or losses on disposition of these allowances should be recorded in Account 421, Miscellaneous Nonoperating Income.

Commission Response. The Commission will limit the scope of the final rule on hedge accounting to allowance futures traded on an organized exchange. Futures trading is an established, standardized practice for which uniform accounting requirements are practical. There are numerous other methods of hedging (*e.g.*, forward contracts) that do not enjoy the same level of standardization as futures contracts and therefore may require different accounting.[60] FASB is reviewing the accounting in these areas and the Commission finds it appropriate in this instance not to go beyond the limited hedge accounting rules adopted herein until FASB's review is completed.

The Commission agrees with certain commenters that Account 124, Other Investments, should be designated as the proper account for recording allowance futures transactions entered into for speculative purposes. However, the Commission is not convinced that other changes are needed in the proposed accounting for futures transactions. From an informational standpoint, there is considerable benefit in requiring deferral of the costs and benefits of futures trading in Account 186 or Account 253 until the futures contract is closed. Further, the amounts of the accounting charges and credits resulting from the Commission's method should be the same as would be produced under FASB Statement No. 80, and would merely be displayed differently on the balance sheet. The Commission fails to see how this difference in display creates a conflict with GAAP. Also, since the Commission is requiring the use of a weighted average cost method in determining the cost of allowances issued from inventory, the costs and benefits from futures transactions, unless deferred as proposed in the NOPR, could affect the income statement before the cost of the related allowances is expensed. This potential mismatch is avoided if separate deferrals in Accounts 186 and 253 are required.

5. *Allowances Acquired Through Exchanges*

The Commission proposed in the NOPR to account for allowances received in exchanges based on the inventory value of the allowances given up.[61] For example, when no monetary consideration (or "boot") is involved, the value of allowances received in an exchange would equal the inventory cost of the allowances given. When a utility pays boot in an exchange, the value of the acquired allowances would be the sum of the inventory cost of the allowances given up and the boot paid.

Comments. NARUC, the Georgia Commission and the Ohio Staff support the proposed rules. The Florida Commission also supports the proposed rules, so long as utility records allow a detailed review of individual transactions, including an identification of transactions between affiliated companies.

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[59] Arthur Andersen, Deloitte & Touche, EEI, Atlantic Electric, Centerior, Commonwealth Edison, Florida Power & Light and PSI Energy.

[60] In fact, according to a FASB Research Report on hedging (FASB, *Hedge Accounting: An Exploratory Study of the Underlying Issues* (1991)), more than 75 different hedging products exist today

[61] *FERC Statutes and Regulations* ¶ 32,481 at p. 32,579.

PSI Energy and the Ohio Staff state that the proposal is consistent with GAAP, specifically with APB Opinion No. 29, "Accounting for Nonmonetary Transactions." PSI Energy asserts that the final rule should refer to APB Opinion No. 29 as the accounting rule for allowance exchanges.

Delmarva Power & Light supports the proposed rule but notes that the NOPR is silent regarding an exchange involving dissimilar nonmonetary assets. Delmarva asserts that when an exchange of dissimilar nonmonetary assets occurs, the accounting should be based on the fair values of the assets involved.

Price Waterhouse opposes the NOPR's proposal to base the value of allowances obtained in an exchange on the inventory cost of the allowances given in exchange, plus any boot paid. Price Waterhouse argues that APB Opinion No. 29 requires that such exchanges be accounted for based on fair value.

AEP opposes the use of historical cost in accounting for allowances acquired through exchanges, citing the same concerns it raised against using historical cost generally.

Commission Response. The Commission has carefully analyzed the comments on allowance exchanges and believes that there is no need to modify the original proposal. To the extent, if any, that GAAP would require the use of fair value in accounting for an exchange when this rule would require the use of historical cost, the Commission deviates from GAAP for reasons stated above. If ratemaking does not follow the accounting for exchanges, the economic effects of any differences can be adequately provided for by recording regulatory assets and liabilities, as discussed below.

D. *Inventory Method*

1. *Weighted Average Cost Method*

The NOPR proposed to use a weighted average cost method for determining the cost of allowances issued from inventory.[62] The Commission stated that this method provides a rational, systematic and objective measure of the cost of allowances used or sold during a period and mitigates the effect of price changes on income and inventory balances. The Commission also stated that if a utility was required to use another inventory method for ratemaking purposes, any differences in allowance inventory values and expense amounts for rate and accounting purposes would be accounted for as regulatory assets and liabilities.

Comments. A number of commenters support the use of the weighted average cost method.[63] The Florida Commission notes that this method comports with the method used in Florida for fuel inventory pricing. The Illinois Commission states that the weighted average cost method prevents utilities from manipulating allowance costs and that such manipulation could cause fluctuations in the expensed allowances as well as in gain or loss recognition. APPA states that the weighted average cost method will cause the least seasonal variation in unit cost.

AICPA argues that the Commission should adopt an averaging method (*e.g.*, weighted average cost) and require use of that method unless a utility demonstrates that another method better reflects the cost of the allowances. Similarly, Deloitte & Touche suggests modifying the rule to express a preference for the weighted average cost method, but allow the use of other methods when appropriate.

The Ohio Staff supports using the weighted average cost method now, but recommends that the Commission reconsider the issue after the Internal Revenue Service rules on the tax treatment of allowances. Alternatively, the Ohio Staff suggests allowing companies to change costing methods if required.

The North Carolina Staff argues that a utility should be allowed to use, for accounting purposes, the inventory method used by most of its regulatory jurisdictions (or the jurisdictions controlling most of the utility's revenues). The North Carolina Staff argues that this approach would reduce the amount of regulatory assets and liabilities, so long as most of the jurisdictions use the same method.

[62] *FERC Statutes and Regulations* ¶ 32,481 at pp. 32,579-82

[63] NARUC, the California Commission, the Florida Commission, the Georgia Commission, the Illinois Commission, PSI Energy and APPA

EEI and many others[64] oppose the mandatory use of a particular inventory method. They argue instead that utilities should be allowed to use any method that is consistent with GAAP, best fits the utility's activity in acquiring and using allowances and is allowed by the primary ratemaking jurisdiction. EEI argues that this approach would avoid unnecessary use of regulatory assets and liabilities.

Several commenters assert that the Commission does not prescribe a single inventory method for materials and supplies or fuel and should not do so for allowances. Virginia Power, for example, notes that Account 154, Plant Materials and Operating Supplies, allows the use of a "cumulative average, first-in-first-out [FIFO], or such other method of inventory accounting as conforms with accepted accounting standards consistently applied."[65] Iowa-Illinois states that it uses the last-in-first-out (LIFO) method for coal inventories and argues that, since allowance usage will track fuel usage, allowance and fuel usage should be valued similarly. Baltimore Gas & Electric argues that the Commission should require only that the inventory method used for allowances be consistent with the method used for the related fuel inventory.

Florida Power & Light argues that, while the weighted average cost method is appropriate for fungible inventories such as fuel, where it is impossible to distinguish between fuel bought at different prices and stored in the same tank, allowances are individually serialized and can be distinguished from each other. Florida Power & Light argues that EPA has proposed to require specific identification of allowances and that the Internal Revenue Service is likely to require specific identification. Florida Power & Light argues that the use of different inventory methods for accounting, tax and environmental purposes would result in unwarranted administrative burdens without discernible benefits to utilities or their ratepayers.

Allegheny Power argues that the specific identification method is appropriate for allowances because it can prevent distortions in the valuation of allowances charged to retail customers. Allegheny Power argues, as an example, that if a company buys allowances for a specific nonaffiliated trade, the cost of those allowances should be allowed to follow that trade and not affect the costs charged to regular customers. Allegheny Power argues that companies may also buy allowances for future needs, and that the average cost method can cause current ratepayers to pay for allowances that will not benefit them.

AEP and Arthur Andersen assert, contrary to the NOPR,[66] that the use of different inventory methods for accounting and ratemaking purposes does not require accounting for differences in inventory values and expense amounts as regulatory assets and liabilities, so long as the ratemaking method is allowed by GAAP. Southern Company argues that recording regulatory assets and liabilities for all differences between inventory values for accounting and ratemaking purposes is unnecessary, costly and administratively burdensome. Cincinnati Gas & Electric argues that such accounting could confuse users of financial statements, with no apparent gain in usefulness or clarity.

EEI and others[67] assert that differences between two generally accepted accounting methods (*e.g.*, when a state commission and this Commission require different methods) are not regulatory assets under FASB Statement No. 71.

Ohio Edison and Penn Power assert that the proposal to use regulatory assets and liabilities to reflect differences in in-

[64] Allegheny Power, the American Gas Association, Baltimore Gas & Electric, Centerior, Central & South West, Cincinnati Gas & Electric, Commonwealth Edison, Con Edison, Consumers Power, Florida Power & Light, Gulf States, Iowa-Illinois, Kentucky Utilities, PacifiCorp, Wisconsin Electric, Atlantic Electric, Delmarva Power, IES Industries, NYSEG, Ohio Edison, PG&E, PJM, Penn Power, Pennsylvania Power & Light, Potomac Electric, PSE&G, Southern Company, Virginia Power and Wisconsin Public Service.

[65] 18 CFR Part 101, Account 154, Plant Materials and Operating Supplies.

[66] *FERC Statutes and Regulations* ¶ 32,481 at pp. 32,581-82

[67] American Gas Association, Baltimore Gas & Electric, Centerior, Central & South West, Commonwealth Edison, Gulf States, Pennsylvania Power & Light, PJM and Wisconsin Public Service.

ventory methods is an unnecessary complication and that concerns continue to be raised by the SEC and accountants about the collectability of regulatory assets. They argue that, while these concerns are often baseless, their existence demonstrates the perception of higher risk associated with such assets.

Atlantic Electric argues that the Commission must assess the effects of allowances valued at present value on the weighted average cost method. Atlantic Electric asserts that amortization of inventory costs can be distorted by commingling costs of allowances associated with future use with costs of allowances with more current application.

AICPA and Deloitte & Touche dispute the NOPR's statement that "there is no need, for inventory purposes, to separately identify which allowances were used . . . ." They argue that serialization of allowances would better enable independent auditors to confirm the existence of allowances and the completion of trades, and allow utilities to design effective internal control and tax systems for allowances.

The Ohio Staff recommends that if EPA adopts serialization, utilities should be required to maintain records detailing the cost associated with each serial number.

Commission Response. Based on careful consideration of the comments, the Commission has decided to adhere to its proposal to require the use of a single inventory method, the weighted average cost method, for allowance inventory accounting. While there is merit in the recommendation of some commenters to allow the use of any inventory method that complies with GAAP and is used for ratemaking purposes, such benefits are outweighed by the need to limit management's discretion in determining income and inventory balances and by the benefits of having a uniform accounting method.

The weighted average cost method has the advantage of objectivity in that it limits management discretion in determining income and inventory balances. By comparison, the other common inventory methods (specific identification, LIFO and FIFO) provide management greater flexibility to manipulate inventory and income balances by timing purchases and sales of allowances and by specifying which allowances are transferred or used.[68] While the Commission has allowed utilities to use these other methods for certain inventories, the allowance inventory will differ from other inventories, in that some allowances will be received at zero cost from EPA and others will be purchased at market price. This cost dichotomy does not exist for other inventories and magnifies management's ability to alter income and inventory balances under inventory methods other than weighted average cost method. The latter method is needed in this instance to prevent the accounting manipulation made possible by the unique disparity of allowance costs.

Also, the uniformity gained by requiring all utilities to use a single inventory method produces other valuable benefits. Many utilities operate in more than one rate jurisdiction and it is possible that all such jurisdictions will not use the same method to price inventory issuances for ratemaking purposes. However, a single inventory method is essential for accounting purposes. For example, if one jurisdiction uses LIFO for ratemaking purposes and another uses FIFO, the principles of sound accounting would militate against the use of both methods in the utility's inventory accounting or the adoption of different inventory pools for each jurisdiction.

Moreover, such jurisdictional differences are likely to occur, and require the use of regulatory asset and liability accounts, regardless of the method the Commission prescribes for accounting purposes. Thus, the use of regulatory asset and liability accounts cannot be avoided merely by allowing utilities to select the accounting method they find desirable.

Apart from multi-jurisdictional conflicts, the use of a uniform inventory method will also help ensure comparability of financial data within the industry. Different inventory methods can substantially alter a utility's apparent financial performance and, even if the method used

[68] *See FERC Statutes and Regulations* ¶ 32,481 at pp. 32,579-80.

is disclosed, make comparisons to other utilities needlessly difficult.

The Commission disagrees with the commenters who assert that, based on FASB Statement No. 71, the use of different inventory methods for ratemaking and accounting purposes would not give rise to regulatory assets and liabilities under the USofA so long as both methods are allowed by GAAP. Regulatory assets and liabilities are defined differently under the final rule than under FASB Statement No. 71. In relevant part, the final rule defines regulatory assets and liabilities as arising from specific revenues, expenses, gains, or losses that would have been included in net income determinations in one period under the USofA's general requirements but for it being probable that such items will be included in a different period(s) for purposes of developing the rates the utility is authorized to charge for its utility services. The final rule, however, requires the use of a single inventory method for allowances—weighted average cost. Thus, under the final rule's definition of regulatory assets and liabilities, the use of a different inventory method for ratemaking purposes could produce regulatory assets or liabilities, even if the other method is allowed by GAAP. Under FASB Statement No. 71, on the other hand, regulatory assets represent differences between the way costs are recognized for regulatory purposes and the way costs are recognized for enterprises in general. Several inventory methods are acceptable under GAAP for industries in general. Thus, under FASB's definition of regulatory assets and liabilities, the use of different inventory methods for rates and accounting would not produce regulatory assets and liabilities so long as both methods are allowed by GAAP.

Some commenters appear to misunderstand how the Commission intends the weighted average cost method to be applied when allowances in inventory are of different vintages. Proposed General Instruction 21(D) stated:

> Inventory included in Accounts 158.1 and 158.2 must be accounted for on a vintage basis using a weighted-average method of cost determination. Allowances usable but not used in the current year must be carried forward to the next vintage year inventory with the appropriate recognition of their inventory cost in the next vintage year's weighted-average cost.

Therefore, the application of this method would not commingle or distort costs of currently usable allowances with the cost of allowances usable only in future years. The only time that the cost of different vintages are combined in the same inventory cost pool is when a currently usable allowance is not used and is therefore available for use in the succeeding year(s).

As to the Internal Revenue Service (IRS) rules on the tax treatment of allowances, the Commission notes that in Revenue Procedure 92-91 (issued November 16, 1992) the IRS issued guidance on certain federal income tax consequences of the allowance program. Nothing in that guidance is directly on point with respect to inventory methods and, in any event, the tax treatment would not dictate the appropriate financial accounting treatment. To the extent there are timing differences between the tax recognition and the financial accounting, the USofA provides for appropriate recognition of the tax effect of such differences.

As to the comments on serializing allowances, the Commission does not dispute that serialization would help independent auditors to confirm the existence of allowances and the completion of trades, and help utilities to design effective internal control and tax systems for allowances. In fact, the Commission would encourage the use of serial numbers for such purposes. For reasons stated above, however, the Commission is adopting a weighted average cost inventory method, which does not require specific identification or cost information by each allowance's serial number.

2. *Vintaging of Allowances*

The Commission proposed in the NOPR to require the grouping of allowances in inventory by vintage, *i.e.*, by the year in which the allowances are first eligible for use.[69] Under this approach, only those allowances usable during the current year (including allowances carried over from

[69] *FERC Statutes and Regulations* ¶ 32,481 at p. 32,582.

prior years) would be included in determining the weighted average cost of the vintage.

Comments. Vintaging is supported by Delmarva Power, NARUC, the California Commission, the Florida Commission, the Georgia Commission, the Illinois Commission, the Ohio Staff and APPA.

Consumers Power opposes vintaging, arguing that the Commission has not required vintaging for any other inventory account. Consumers Power asserts that vintaging of allowances will impose an unnecessary administrative burden.

The Wisconsin Municipal Group also opposes vintaging, arguing that vintaging is inconsistent with the NOPR's statements that all allowances are fungible. The Wisconsin Municipal Group asserts that the weighted average cost of the allowances expensed should be calculated using all allowances in inventory.

Commission Response. The Commission will retain the vintaging requirement in the final rule. Vintaging is essential for proper costing of allowances used or otherwise disposed of during each year. An allowance not yet eligible for use does not have the same value as an allowance currently eligible for use. To include as-yet-unusable allowances with the weighted average cost of currently usable allowances would, in the Commission's view, produce distorted costing.

E. *Expense Recognition of Allowances*

1. *Timing of Recognition*

The Commission proposed in the NOPR to require utilities to charge to expense on a monthly basis the number of allowances, including fractional amounts, corresponding to the amount of sulfur dioxide emitted.[70] The Commission noted that this method results in the recognition of expenses during the period in which the related energy is produced and used and matches costs to the revenues received for production, thus accurately reflecting the results of operations during each period.

Comments. Many commenters supported the proposal for monthly allowance expense accrual.[71] EEI comments that this approach is consistent with the principle of accrual accounting.

Arthur Andersen recommends that the cost basis used for expense recognition should be recalculated on a weighted average cost, year-of-eligible-use basis each month in determining the monthly expense amount.

Florida Power & Light agrees that allowances should be expensed on a monthly basis, but argues that the expensing should be based on management's annual compliance plan. Florida Power & Light argues that, since months are integral parts of an annual period and not discrete periods, monthly costs should reflect the relative portion of the total anticipated annual allowance expense according to the compliance plan.

Coopers & Lybrand recommends replacement of the NOPR's proposal with a reference to APB Opinion No. 28, "Interim Financial Reporting."[72] Coopers & Lybrand argues that APB Opinion No. 28 provides sufficient guidance on costs and expenses for interim reporting purposes.

APPA states that, for some utilities with generating units using alternative monitoring systems, emission data may not be available when the utility closes its expense records for a given month. APPA asserts that these utilities should be allowed to rely on estimates based on fuel sampling and use, with a year-end true-up coinciding with the extended allowance recording period adopted in EPA's regulations. Similarly, Delmarva Power asserts that allowances should be charged to expense monthly based on an estimate of the number of allowances used each month, with a year-end true-up to actual usage.

EPA notes that whenever emission data are missing or unavailable, a utility must calculate emissions consistent with estimates prescribed by EPA. EPA asserts that allowance expensing should be based on whatever data (including data substituted for missing data) are used to determine emissions and allowance obligations

[70] *FERC Statutes and Regulations* ¶ 32,481 at p. 32,583.

[71] NARUC, the Florida Commission, the Georgia Commission, the Illinois Commission, the Ohio Staff, EEI, Centerior, Cincinnati Gas & Electric, Commonwealth Edison, Consumers Power, Gulf States, Pennsylvania Power & Light, PSI Energy and APPA.

[72] APB Opinion No 28, *Interim Financial Reporting, in Accounting Statements—Original Pronouncements* (1991).

under the Clean Air Act. EPA argues that this result would properly correlate a utility's allowance accounting with its actual allowance obligations and costs.

Commission Response. The Commission will adopt the proposal to require utilities to charge to expense on a monthly basis the cost of allowances, including fractional amounts, corresponding to the amount of sulfur dioxide emitted. As suggested by Arthur Andersen, the cost basis used for expense recognition should be recalculated on a weighted average cost, year-of-eligible-use basis each month. The Commission recognizes that in some instances actual emission data may not be available when the utility closes its expense records for a given month. The use of reasonable estimates in such circumstances, with true-ups to actual data in the month the facts become known, is acceptable for financial reporting purposes.

2. *Account Used for Recognition*

The Commission proposed in the NOPR to require utilities to record the expense of allowances in a new account entitled Account 509, Allowances.[73] The Commission stated that classification in Account 509 would properly recognize the nature of allowances as part of the cost of production, but would not require any particular ratemaking treatment.

Comments. The proposed rule is supported by Arthur Andersen, NARUC, the Florida Commission, the Georgia Commission and the Ohio Staff.

The Illinois Commission does not oppose the creation of Account 509 but argues that utilities should be allowed to modify this requirement to conform to the accounting mandated by state regulators. The Illinois Commission argues that it may wish to allow fuel clause recovery of allowance expenses and, to do so, may have to require utilities to record allowance expenses in Account 501, Fuel. Similarly, Duke Power argues that mandating the use of an account other than Account 501 will preclude many companies from recovering allowance costs through fuel clauses under existing statutes.

EEI and many other commenters[74] support the recognition of allowance expense in a new subaccount within Account 501. Iowa-Illinois argues, for example, that using a new subaccount of Account 501 would facilitate fuel clause recovery because many fuel clauses, including those in Iowa-Illinois' retail jurisdictions, limit recoverable costs to those included in specific accounts. PSI Energy argues that using a subaccount of Account 501 would not dictate any particular ratemaking treatment or violate the goal of rate neutrality because state commissions will thoroughly review the rate treatment of allowances.

AEP opposes the creation of a new account, instead supporting the use of existing accounts such as Account 501 or Account 506, Miscellaneous Steam Power Expenses. AEP argues that short-term sales are generally priced at full recovery of fuel costs plus partial recovery of O&M costs, so that using existing accounts, particularly Account 501, may allow recovery from short-term energy buyers of the full fair value of the allowances used for the sale.

Virginia Power argues that the cost of using allowances obtained in fuel-related trades should be recognized in Account 501. As an example, Virginia Power describes a sale of high sulfur coal bundled with allowances, in which the allowances are needed because burning the high sulfur coal will generate substantial emissions.

APPA opposes the use of Account 501 for allowances. APPA argues that allowances should be held in a separate account to facilitate correct rate mechanisms such as formula rates. APPA argues that the recovery of allowances in rates will be a distinct and separate issue, so that allowances should not be treated as part of an aggregate figure.

Commission Response. The Commission will adopt Account 509, Allowances, as the proper account for recording allowance expenses. Most of the commenters opposing the use of Account 509 argue that the use of other existing accounts would facilitate rate recovery. However,

[73] *FERC Statutes and Regulations* ¶ 32,481 at p. 32,583.

[74] Allegheny Power, Baltimore Gas & Electric, Central & South West, Cincinnati Gas & Electric, Commonwealth Edison, Consumers Power, Delmarva Power, Gulf States, IES Industries, Iowa-Illinois, Ohio Edison, Penn Power, PJM, Potomac Electric, PSI Energy and PSE&G.

as explained above, the Commission intends for this accounting rule to be rate neutral, *i.e.*, to not favor one particular rate treatment over another. Using a new account will best accomplish this objective. Furthermore, the use of a separate account for expensing allowances will simplify access to useful information on a utility's allowance program.

3. *Allowance Inventory Shortages*

The NOPR proposed that if a utility emits more sulfur dioxide than it has allowances in inventory, the utility should accrue in inventory (Account 158.1) the estimated cost of obtaining the needed allowances.[75] The utility would charge Account 158.1 for the estimated cost of the needed allowances and credit the proper liability account. Any difference between the estimated and actual cost of allowances would be charged to Account 158.1.

Comments. Consumers Power, NARUC, the Florida Commission and the Georgia Commission support the proposed rules. The Ohio Staff generally agrees with the proposed rule but recommends that any estimated amounts charged to the allowance inventory account should be designated as estimates. The Ohio Staff also recommends that utilities be required to keep records supporting the cost estimates.

A number of commenters argue that the cost of meeting an allowance inventory shortage should be expensed immediately, along with the related liability, instead of being charged to inventory.[76] AICPA argues that any difference between actual and estimated costs should be charged to expense rather than Account 158.1.

Commission Response. The Commission will adopt the accounting proposed in the NOPR. The Commission proposed using Account 158.1 for recording allowance accruals, instead of direct expensing, to be consistent with the use of the weighted average cost method of costing allowances issued from inventory, and to ensure the completeness of information reported to the Commission annually on utility allowance programs.

To clarify the Commission's intent, however, there should be no delay in expensing the estimated cost of allowances when a utility has fewer allowances than it needs for its emissions to date. When accruals are required, Account 158.1 effectively becomes a clearing account in which the monthly cost of accrued allowances is charged and credited in the same month. In such cases, the use of Account 158.1 will provide auditable information needed to complete the required reporting schedule. Likewise, when differences between the estimated cost of allowances and the actual cost become known, the adjustments should be made through Account 158.1 and Account 509 within a single month. With these clarifications, the proposed accounting meets the commenters' concerns on expensing allowance costs in the proper period and at the same time ensures the completeness of data for Account 158.1.

4. *Penalties*

The Commission stated in the NOPR that, if a utility incurs a fine or penalty as a result of noncompliance with the CAAA, the USofA requires the fine or penalty to be recorded in Account 426.3, Penalties, a below-the-line account.[77]

Comments. Commenters agreeing with the proposed treatment include Consumers Power, NARUC, the California Commission, the Florida Commission, the Georgia Commission and the Illinois Commission.

EEI and Allegheny Power propose the designation of penalty accounts both below and above the line.[78] Allegheny Power asserts that the NOPR assumed that penalties are not recoverable in rates, an assumption that Allegheny Power argues may not be true depending on the circumstances and on regulatory decisions.

EEI and Florida Power & Light assert that penalties imposed for noncompliance should be reviewed to determine the cause of the noncompliance. They argue that if

[75] *FERC Statutes and Regulations* ¶ 32,481 at p. 32,583.

[76] AICPA, Arthur Andersen, Deloitte & Touche, EEI, Atlantic Electric, Baltimore Gas & Electric, Commonwealth Edison, Gulf States, Iowa-Illinois and Pennsylvania Power & Light

[77] *FERC Statutes and Regulations* ¶ 32,481 at p. 32,583.

[78] "Above-the-line" accounts contain amounts that reflect operating income and expenses and are generally included in rates.

a utility has acted prudently to meet emission limits and events outside its control caused the noncompliance, the penalty should be allowed in cost-of-service.

The North Carolina Staff opposes the creation of an above-the-line account for CAAA-related penalties. The North Carolina Staff asserts that designation of an above-the-line account could encourage a utility to record penalties in that account without prior regulatory approval, due to its belief that the costs should be recovered in rates. The North Carolina Staff asserts that such actions not only may misclassify such costs, but also would make it more difficult to ascertain the utility's total penalties.

Commission Response. The Commission continues to believe that the proper account to use for all fines and penalties incurred through noncompliance with the CAAA is Account 426.3, Penalties. However, the use of this account is not intended to preclude a ratemaking body from considering any amounts recorded therein for ratemaking purposes. The Commission notes, however, that IRS Revenue Procedure 92-91, discussed above, states that the $2,000 per ton penalty imposed under the CAAA is not deductible for Federal income tax purposes.

F. *Gain or Loss on Disposition of Allowances*

The NOPR proposed a two-step process for accounting for gains and losses on the sale, exchange, or other disposition of allowances. The first step would be to recognize the gain or loss in income, in either of two new above-the-line accounts: Account 411.8, Gains from Disposition of Allowances, or Account 411.9, Losses from Disposition of Allowances. The second step would be to recognize the economic effect of regulators' actual or expected ratemaking treatment of the gain or loss, by recording entries in new generic accounts for regulatory assets and liabilities: Account 182.3, Other Regulatory Assets; Account 244, Other Regulatory Liabilities; Account 407.3, Regulatory Debits; and Account 407.4, Regulatory Credits.

Comments. NARUC, the Florida Commission, the Georgia Commission, the Illinois Commission and the Ohio Staff support the proposed treatment. NARUC states that the proposed treatment would allow gains and losses to remain in the new accounts for regulatory assets and liabilities pending a ruling by state regulators.

The Michigan Staff proposes an accounting treatment for using the gain from allowance sales to offset expenditures made to reduce sulfur dioxide emissions. Under this proposal, the net gain from allowance sales would first be recorded as a deferred credit in a new clearing account. The utility's management then would decide how to use the funds. If the funds are passed on to stockholders and/or ratepayers, the clearing account would be reduced and Account 244, Other Regulatory Liabilities, would be credited. If the funds are used to offset expenditures made to reduce emissions, the clearing account would again be reduced, but the credit entries would be made in the affected plant, deferred debit, or operating expense accounts. The Michigan Staff argues that this treatment would encourage utilities to finance emission reductions with the funds generated from allowance sales.

Allegheny Power argues that the accounting for gains and losses on disposition of allowances should allow for deferrals with subsequent amortization over the expected benefit period and/or in accordance with regulatory direction. Allegheny Power analogizes to previous investment tax credit programs.

PSI Energy, Detroit Edison and Atlantic Electric oppose the two-step process of first recording gains or losses in income and then accounting for the regulatory treatment of such gains or losses. PSI Energy asserts that this process could distort the income statement by accounting for a single transaction as two offsetting amounts in the income statement. PSI Energy suggests instead that the economic effects of the regulatory treatment of allowance-related gains or losses should be accounted for under the provisions of FASB Statement No. 71.

AICPA and Arthur Andersen argue that the proper accounting for a gain on sale of allowances is as follows: (1) If there is uncertainty as to the regulatory treatment, the gain should be deferred pending resolution of the uncertainty; (2) If there is certainty as to the regulatory treatment, the gain should be accounted for consistent with FASB Statement No. 71, to the extent a regulatory liability results; and (3) If the gain, or any part thereof, accrues to shareholders, that amount should be recognized as income currently and recorded in Account 421, Miscellaneous Nonoperating Income. AICPA argues that a loss should be recognized currently and recorded in Account 421, unless a regulatory asset is established under FASB Statement No. 71.

A number of commenters propose the designation of accounts both above and below the line for gains and losses on allowance trading.[79] Price Waterhouse argues that provision should be made for below-the-line recognition when circumstances warrant. EEI argues that below-the-line accounts are needed because state regulators may not always follow the procedure proposed by the Commission. Centerior argues that using only above-the-line accounts unfairly prejudices future ratemaking with a bias toward allocating these amounts solely to customers.

A number of commenters see no need to create new accounts for gains and losses on disposition of allowances and instead suggest modifying existing accounts, both above and below the line, to accommodate gains and losses on allowance trades.[80] PJM and PSE&G assert, for example, that new accounts are not needed because the Commission has stated that the sale of allowances is the same as the sale of any other asset.

AEP argues that the final rule should prescribe accounting for sharing gains and losses between ratepayers and shareholders. AEP argues that when a commission's past precedent indicate that gains will be shared between ratepayers and shareholders, the latter's portion of the gain should be initially recorded below-the-line to avoid subsequent reclassification.

Deloitte & Touche argues that a gain accruing to the benefit of shareholders should be credited directly to Account 421, Miscellaneous Nonoperating Income, rather than first being credited to Account 411.8, Gains from Disposition of Allowances. Otherwise, Deloitte & Touche states, the same gain could be reported twice in the income statement.

Commission Response. Upon considering the comments on this issue, the Commission has decided to simplify the proposed accounting for gains and losses on disposition of allowances. The NOPR proposed a two-step process under which a utility would first recognize these gains and losses in its income statement and then account for the economic effects of the regulatory treatment by recording a regulatory liability or asset. The Commission now considers this two-step process unnecessary and undesirable. Instead, the Commission will adopt, in large part, the suggestions of AICPA and Arthur Andersen.

Gains on dispositions of allowances should be accounted for as follows. First, if there is uncertainty as to the regulatory treatment, the gain should be deferred in Account 254, Other Regulatory Liabilities, pending resolution of the uncertainty. Second, if there is certainty as to the existence of a regulatory liability, *e.g.*, if regulators have ordered the gain to be passed onto ratepayers over several years, the gain will not be recognized in income. Instead, it will be credited to Account 254, with subsequent recognition in income when reductions in charges to customers occur or the liability is otherwise satisfied. Third, all other gains will be credited to Account 411.8, Gains from Disposition of Allowances.

Losses on disposition of allowances that qualify as regulatory assets should be charged directly to Account 182.3, Other Regulatory Assets. All other losses should be charged to Account 411.9, Losses from Disposition of Allowances.

The Commission declines to adopt the suggestion of several commenters that it provide for below-the-line recognition of gains or losses on disposition of allowances (other than gains or losses relating to speculative investments, as discussed above). The USofA does not, and should not, require each transaction to be shown above or below the line based upon whether customers or stockholders bear the expense or receive the benefits of the transaction. Instead, the nature of the transaction determines whether it is shown as utility operating income (above-

[79] Price Waterhouse, EEI, Allegheny Power, Baltimore Gas & Electric, Centerior, Florida Power & Light, GPU, Iowa-Illinois, PacifiCorp and Pennsylvania Power & Light.

[80] Baltimore Gas & Electric, Commonwealth Edison, GPU, Ohio Edison, PJM, PSE&G and Penn Power.

the-line) or as other income and deductions (below-the-line). With enactment of the CAAA, allowance transactions are expected to become an integral part of utility operations, especially if the market for allowance trading develops as intended. The above-the-line classification required herein does not dictate how gains and losses on dispositions of allowances should be apportioned between ratepayer and stockholders, but merely reflects the fact that allowance transactions are a part of utility operations.

G. *Regulatory Assets and Liabilities*

The Commission proposed in the NOPR to provide accounting for regulatory assets and liabilities, *i.e.*, assets and liabilities created through the ratemaking actions of regulatory agencies and not specifically provided for in other accounts. The NOPR proposed to create four new accounts for regulatory assets and liabilities: Account 182.3, Other Regulatory Assets; Account 244, Other Regulatory Liabilities; Account 407.3, Regulatory Debits; and Account 407.4, Regulatory Credits. The first two are balance sheet accounts; the latter two are income accounts.

As proposed, Account 182.3 would include costs incurred and charged to expense which have been, or are soon expected to be, authorized for recovery through rates and which are not specifically provided for in other accounts. Regulatory assets would be recorded by charges to Account 182.3 and credits to Account 407.4. Amounts in Account 182.3 would be amortized to Account 407.3 over the appropriate rate recognition period.

Account 244 would include liabilities imposed by the ratemaking actions of regulatory agencies and not specifically provided for in other accounts. Included in Account 244 would be revenues or gains realized and credited to income that the company is required, or is expected to be required, to use to reduce future rates. Regulatory liabilities would be established by credits to Account 244 and debits to Account 407.3. Amounts included in Account 244 would be amortized to Account 407.4 over the appropriate rate recognition period.

Support for the NOPR

National Fuel Gas, the Florida Commission and the Ohio Staff support the proposed rule. The Ohio Staff states that the proposed treatment will provide uniformity in the way utilities report the economic effects of regulatory actions and will facilitate review of regulatory assets and liabilities.

Support for the Status Quo

Virginia Power and PSI Energy oppose any change in current accounting practices for regulatory assets and liabilities. Virginia Power argues that the accounting practices used over the years have worked well and should be considered GAAP for regulated entities. PSI Energy argues that the USofA already provides sufficient guidance and accounts for regulatory assets and liabilities and that financial reporting rules ensure the itemization in financial statements of significant regulatory assets or liabilities.

Procedural Objections

A large number of commenters urge deletion of this issue from this proceeding and initiation of a separate rulemaking on regulatory assets and liabilities.[81] Many of these commenters assert that the issue of regulatory assets and liabilities is too important and complex to be included in a rulemaking on accounting for allowances.

Pennsylvania Power & Light and Wisconsin Electric argue that this proceeding should address only those regulatory assets and liabilities related to allowances and that other regulatory assets and liabilities should be considered in a separate rulemaking.

AICPA, Arthur Andersen and Deloitte & Touche argue that the following issues should be exempted from the final rule pending further study: whether FASB instructs regulated enterprises to account for certain effects on income taxes only on the balance sheet, not on the income statement; whether deferred returns from phase-in plans and other similar deferrals should be reported below-the-line; and

[81] AICPA, Arthur Andersen, Coopers & Lybrand, Deloitte & Touche, EEI, Central & South West, Commonwealth Edison, Con Edison, Detroit Edison, Duke Power, Gulf States, Kansas City Power & Light, Kentucky Utilities, PJM, Potomac Electric, PSE&G and Wisconsin Public Service.

whether some items are classified in a way unique to the regulatory process and are not accounted for as proposed in the NOPR.

General Substantive Objections

AEP argues that, according to FASB, regulatory assets and related deferred income taxes should be reflected only on the balance sheet. PSI Energy argues that the income statement presentation of phase-in plans should be specifically excluded from the final rule.

AEP also argues that, if a utility is deferring significant costs, *e.g.*, through a phase-in plan, and is accruing a return on the unrecovered balances, the NOPR may wrongly move the credit for the deferred return from below-the-line to above-the-line. AEP argues that this result would distort both operating and non-operating income and is contrary to the regulatory intent to provide the credit as compensation to investors, not as a reduction of the cost of service.

Centerior argues that a new account is needed for the deferral of return through a carrying charge because crediting such amounts to Account 407.4, an above-the-line account, would be inconsistent with past Commission practice. Centerior argues that the Commission has consistently required the carrying charge to be credited to Account 421, Miscellaneous Nonoperating Income, a below-the-line account.

EEI argues that the Commission should allow certain regulatory assets and liabilities, such as the gross-up of portions of previously-recorded AFUDC, to be classified with the plant accounts. EEI also argues that certain costs should be presented separately from other regulatory assets and liabilities. EEI states, for example, that the net phase-in costs capitalized in each period or the net amount of previously allowable phase-in costs recovered during each period should be reported as a separate item of other income or expense in the income statement.

Applicability of Accounts 407.3 and 407.4

EEI argues that utilities should be allowed to use accounts other than 407.3 and 407.4 if state regulators have previously allowed such use. EEI argues that if state regulators have allowed the use of other accounts, the requirement to use Accounts 407.3 and 407.4 should apply only prospectively. Allegheny Power and Kansas City Power & Light assert that use of the new accounts should not be required if the commission with primary ratemaking jurisdiction requires the use of other accounts.

Southern Company argues that the new accounts should apply only to new regulatory assets and liabilities. Southern Company asserts that the new accounts could lead to cost recovery problems under existing contracts and joint ownership agreements under which costs previously deferred are now being amortized to an account reflected in formulary billings. Southern Company argues that a change in account classification would jeopardize cost recovery and could require costly renegotiation of contracts and agreements.

AEP argues that, if Accounts 407.3 and 407.4 are adopted, these accounts should not apply to deferred income taxes. AEP argues that the needed information is not always available for individual book/tax timing differences, especially those involving plant-in-service. AEP argues that identifying the proper accounts in which deferred taxes should be recorded can be difficult or impossible.

Several commenters argue that regulatory assets and liabilities should be recorded in income statement accounts reflecting the nature of the underlying transactions, regardless of when the transactions are recognized.[82] The American Gas Association, for example, asserts that financial statement readers are more interested in the nature of a company's transactions than in the differences between GAAP for non-regulated and regulated businesses. The Association asserts that, when necessary, utilities and regulators can determine the effect of regulation for ratemaking purposes and that these differences should not be the focus of the statements.

Effect on Coverage Ratios

EEI, AEP, Gulf States and Virginia Power assert that using new Accounts 407.3 and 407.4 will distort the computa-

[82] American Gas Association, Baltimore Gas & Electric, Columbia Gas, Con Edison, Virginia Power and Wisconsin Public Service.

tion of coverage ratios under SEC rules. They assert that, under the standard coverage formula, the adjustments to income taxes would be added back to determine earnings for coverage purposes, but the related adjustments to the regulatory asset and liability income statement accounts would not be added back.

Defining Regulatory Assets and Liabilities

A number of commenters argue that regulatory assets and liabilities should be defined more consistently with FASB Statement No. 71.[83] They argue, for example, that the USofA should allow recognition of regulatory assets and liabilities only when rate recovery is probable, i.e., likely to occur, not just reasonably expected. Otherwise, they argue, utilities might have to report the same transactions under two sets of accounting principles.

NARUC notes that Account 182.3 includes regulatory assets related to the amortization or normalization of certain costs, and suggests that the account be clarified to include only those regulatory assets "related to the amortization of specific and significant non-recurring or infrequent operating or maintenance expense items . . . ." In support, NARUC states that the word "normalization" is ambiguous. The North Carolina Staff similarly argues that, in any ratemaking decision, regulators may adopt several adjustments to set rates at an average, or "normal" level, but not to provide for recovery of a specific cost in a period other than the one in which it would be recognized for accounting purposes. The North Carolina Staff argues that, contrary to the implication in the NOPR, it would be inappropriate to record a regulatory asset or liability for such adjustments.

Inconsistent Classification

Many commenters note that proposed Account 182.3, Other Regulatory Assets, is classified as a deferred asset while proposed Account 244, Other Regulatory Liabilities, is classified as a current liability. A number of commenters argue that regulatory assets and liabilities should both be classified in deferred accounts.[84] Others propose the establishment of both current and deferred accounts for both regulatory assets and liabilities.[85] Still others find either of these two approaches acceptable.[86] The American Gas Association and Con Edison argue that the classification of a regulatory asset or liability as current or deferred should be determined by GAAP.

Commission Response. The Commission now believes that, although separate accounts for regulatory assets and liabilities should still be established in this rulemaking, the two-step process described in the NOPR is not generally necessary and in some instances may contribute to inappropriate results. Based upon the comments received, the Commission will make certain changes in the accounting required for regulatory assets and liabilities.

For consistency in the balance sheet presentation of regulatory assets and liabilities, the Commission will renumber proposed Account 244, Other Regulatory Liabilities, to Account 254. Account 254 will be in the deferred credits section of the balance sheet, thus paralleling the placement of Account 182.3, Other Regulatory Assets, in the deferred debits section of the balance sheet.

The Commission will require that deferred returns and/or carrying charges accrued on regulatory assets and liabilities be credited to Account 421, Miscellaneous Nonoperating Income, or charged to Account 431, Other Interest Expense, as appropriate. Both of these accounts are below-the-line. This change, recommended by several commenters, is needed to conform the required accounting treatment to the accounting used in recording deferred returns and/or carrying charges in other circumstances.

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[83] AEP, AICPA, Arthur Andersen, EEI, Centerior, Commonwealth Edison, Consumers Power, the Georgia Commission, NARUC, the North Carolina Staff, Price Waterhouse, PSI Energy and Virginia Power

[84] AEP, Baltimore Gas & Electric, Centerior, Delmarva Power, PacifiCorp, PJM, Ohio Edison, Penn Power and Wisconsin Electric.

[85] Allegheny Power, Central & South West, PG&E, Virginia Power, Price Waterhouse, and Potomac Electric.

[86] EEI, Cincinnati Gas & Electric, Commonwealth Edison, Gulf States, IES Industries, NYSE&G, PSI Energy and Wisconsin Public Service

The Commission will also redefine regulatory assets and liabilities to use terms more similar to those used in FASB Statement No. 71, in order to avoid unnecessary differences between financial statements issued for regulatory purposes and general purpose financial statements. The term "probable," as used in the definition adopted herein for regulatory assets and liabilities, refers to that which can reasonably be expected or believed on the basis of available evidence or logic but is neither certain nor proved.[87]

Finally, to reduce other possible conflicts with current practices, the Commission will modify the proposed text of the accounts for regulatory assets and liabilities. Under the originally-proposed accounting for regulatory assets and liabilities, all entries to Accounts 182.3 and 244 (now 254) would have been through charges or credits to Accounts 407.3 and 407.4. Also, the proposed accounting would have required current expense (revenue) recognition consistent with the USofA requirements as determined without regard to the creation of regulatory assets and liabilities; whereas, the current practice is generally not to recognize the expense (revenue) but to capitalize the cost (or recognize a liability). The proposed accounting would therefore have affected income statement accounts even though net income was not affected (*i.e.*, a liability would be recorded along with an equal regulatory asset or an asset would be recorded along with an equal regulatory liability). Although net income would not have been affected, the NOPR's proposed accounting could have distorted various financial ratios, such as pre-tax interest coverage calculations. Thus, the Commission will adopt Accounts 407.3 and 407.4, as modified, to provide for separate income and expense recognition only in appropriate situations, such as for the net amount capitalized for phase-in plans in each period and the net amount of previously capitalized allowable costs recovered during each period.

H. *Reporting Requirements*

Based on the proposed accounting for allowances and regulatory-created assets and liabilities, the NOPR proposed to require new schedules and changes to existing schedules in the Annual Reports (Forms 1, 1-F, 2 and 2-A) filed by electric utilities, licensees and natural gas companies. Of particular note, the NOPR proposed a new schedule for reporting the number and cost of allowance transactions, to include a utility's beginning- and end-of-year balance of allowances; acquisitions by issuance and returns from EPA; acquisitions by purchases and transfers; relinquishments by charges to expense; relinquishments by sales and transfers; net sales proceeds; and gains and losses.

Allowance Trading Information

EPA supports the NOPR's proposal to require reporting of allowance trades, asserting that the information will be helpful to other regulators and traders in the allowance market. The Ohio Staff also supports the proposed reporting requirements and asks that utilities additionally be required to report market-related information, *e.g.*, each allowance trade, the parties thereto and the corresponding amounts. The Ohio Staff asks the Commission to compile the market information and make it available to all state commissions.

The Iowa Working Group argues that market price and contract term data must be collected and made available because of the planned or expected use of fair value for certain accounting purposes (*e.g.*, inter-affiliate trades) and ratemaking purposes. The Group asks the Commission to compile a database on allowance prices and contract terms for all jurisdictional utilities beginning in 1994, for two years or until the private market takes over this function. The Group proposes that the Commission require quarterly filings of price and contract term information, and compile the information in a publicly available database, omitting the names of the traders.

APPA argues that the proposed reporting requirements are not adequate for purposes of determining fair market value at the time of a given trade. APPA

[87] Webster's New World Dictionary of the American Language, 2d college ed. [New York: Simon and Schuster, 1982] at p. 1132. This is the meaning referred to in FASB Concepts Statement No. 6, *Elements of Financial Statements*, ¶ 25 n.18 and ¶ 35 n.21, (1985) (superseding FASB Concepts Statement No. 3), *in Accounting Statements—Original Pronouncements* (1991).

argues that the Commission should require full and timely public disclosure of the details on allowance trades, including market price information. APPA and the NC Municipal Agency assert that such information will promote a vigorous allowance market by minimizing uncertainties about reasonable prices and terms. APPA argues that the availability of price information also will discipline the market by facilitating public inspection of trades by utilities, brokers, regulators and consumer advocates. APPA asks the Commission to consider using an electronic bulletin board to collect information as each transaction closes, requiring identification of the purchaser and seller, quantity, price, vintage, and terms and conditions.

EEI and others[88] argue that information on allowance trades should be kept confidential. EEI argues, for example, that EPA does not require the parties to disclose the price in private sales. AEP asserts that, if a public market does not develop, trading information will be private and, if disclosed, could adversely affect future trading possibilities. PSI Energy asserts that, while the information in the proposed reporting requirements will be needed for an active trading market and informed regulatory decisions, there are more appropriate, less detailed means of acquiring the information, *e.g.*, through market-driven mechanisms such as brokers, newsletters or futures contracts on the Chicago Board of Trade. Virginia Power, Consumers Power and Pennsylvania Power & Light argue that information on allowance trades should be reported in aggregate, not by the specifics of each trade. These commenters and others express concern generally about the scope of information sought on allowances, and suggest conforming this reporting requirement to the requirements for nuclear fuel materials, materials and supplies or the monthly cost and quality of fuels.

Technical Changes

Consumers Power asserts that Instruction No. 2 for page 228, Allowances, requiring that all allowance acquisitions be recorded at historical cost, is not consistent with proposed General Instruction 21, prescribing the use of fair value for the acquisition of allowances eligible for use in different years. Consumers Power argues that Instruction No. 2 should be expanded to address reporting for allowances usable in future years.

Consumers Power also argues that lines 31-36 and 42-46 of page 228, requiring data on Net Sales Proceeds and Gains or Losses by the period in which the allowances are first eligible for use, are not needed for analyzing the activity of the allowances account and should be eliminated.

Consumers Power asserts that lines 37-40 of page 228, requiring data on allowances withheld, do not provide for any reduction in withheld allowances sold at EPA's direct sales or auctions. Consumers Power recommends the addition of a line for sales to reduce the Allowances Withheld amount to what is available to the utility.

The Wisconsin Municipal Group argues that page 228 should be amended to show the calculation of the weighted average cost of allowances.

Pennsylvania Power & Light seeks clarification of a possible inconsistency on the Statement of Cash Flows, pages 120 and 121 of FERC Form 1. Pennsylvania Power & Light notes the proposed identification, in the section for investment activities, of the net increase (decrease) in allowances and assumes that this item includes only allowances held for speculation. Pennsylvania Power & Light argues that a similar line should be included in the section on operating activities for allowances held for the utility's use.

AEP proposes raising the level below which a utility, for reporting purposes, may aggregate minor items in Account 182.3, Other Regulatory Assets, and Account 244, Other Regulatory Liabilities. The Commission proposed in the NOPR to allow grouping of items equal to less than five percent of the year-end balance or amounts less than $50,000, whichever is less. AEP proposes changing $50,000 to $100,000, in order to avoid excessive reporting detail on immaterial amounts.

[88] AEP, Centerior, Consumers Power, Detroit Edison, Gulf States, Iowa-Illinois, PJM, PSE&G, Virginia Power and Wisconsin Electric.

Pennsylvania Power & Light asserts that page 232, Other Regulatory Assets, and page 278, Other Regulatory Liabilities, should include an additional column for Balances at Beginning of Year, to match similar presentations elsewhere in FERC Form 1.

Washington Gas recommends expanding the proposed instructions to Form Nos. 2 and 2-A, to clarify that the amortization period for regulatory assets and liabilities need not be disclosed when regulators have not issued a final order establishing the appropriate rate recovery period.

Baltimore Gas & Electric and Florida Power & Light argue that the proposed reporting of regulatory assets and liabilities in FERC Forms 1 and 2 is inconsistent with the proposed accounting for those assets and liabilities. Baltimore Gas & Electric asserts that, under the proposed accounting, regulatory assets and liabilities may be created and extinguished only by entries to new accounts 407.3 and 407.4. Baltimore Gas & Electric asserts, however, that the proposed pages in Forms 1 and 2 would require disclosure of the offsetting income statement accounts used to set up and amortize regulatory assets and liabilities.

The Michigan Staff recommends revising the proposed instructions for Account 244, Other Regulatory Liabilities, in Part 201 to delete the reference to the disposition of allowances, unless it is anticipated that natural gas companies will own allowances as part of their regulated business. The Michigan Staff asserts that if a natural gas company did acquire allowances, consideration should be given to recording their cost in Account 121, Nonutility Property.

Commission Response. Upon considering the comments on allowance trading information generally, the Commission has decided to adhere, for now, to the approach proposed in the NOPR. Requiring annual reporting of allowance trading information strikes a balance between those commenters seeking confidentiality for trading data and those seeking more extensive disclosure than was proposed in the NOPR.

The Commission does not agree that the reporting requirements will create a competitive burden for utilities required to file data on revenues from allowance sales and costs of allowance purchases. The Commission is not persuaded that such utilities will be at a competitive disadvantage. Also, such price data is needed by regulators in setting rates and in determining the fair value of allowances and may be helpful to market participants considering allowance trading.

On the other hand, the Commission does not yet perceive a definite need to increase the reporting requirements for allowance trading. While more frequent reporting of allowance trading, *e.g.*, monthly reporting, might prove useful to market participants, other sources may develop to meet any such need and, if so, would obviate the need for more frequent reporting to this Commission. For example, the data and information available from EPA auctions, the Chicago Board of Trade and other sources might exceed the information the Commission is requiring.

For this reason, the Commission will adopt the proposed reporting requirements on allowance trading. In doing so, however, the Commission acknowledges that the issue of the quality and timeliness of data available to regulators and market participants may need to be revisited, depending on how other sources of market information develop.

The Commission has carefully reviewed the other comments on the Annual Report forms and believe that only minor changes are required in the NOPR's proposals. The Commission will: (1) add a line in the Net Cash Flow from Operating Activities section of the Statement of Cash Flows (page 120) to show the net increase or decrease in allowance inventories; and (2) clarify that the line for the net increase or decrease in allowances shown in the Net Cash Flows from Investment Activities section (page 121) applies only to allowances held for speculation. Also, on pages 228 and 229, the Commission will insert the lines for net sales before the line that shows end-of-year balances. Finally, the Commission will make other minor changes to conform the reporting forms to the accounting changes adopted above.[89]

IV. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA)[90] requires rulemakings either to contain a description and analysis of the effect the proposed rule will have on small entities or to certify that the rule will not have a substantial economic effect on a substantial number of small entities. Because most public utilities and gas companies do not fall within the RFA's definition of small entities,[91] the Commission certifies that this rule will not have a "significant economic impact on a substantial number of small entities."

V. Environmental Statement

Commission regulations require that an environmental assessment or an environmental impact statement be prepared for any Commission action that may have a significant effect on the human environment.[92] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment.[93] No environmental consideration is necessary for the promulgation of a rule that is clarifying, corrective or procedural or that does not substantively change the effect of legislation or regulations being amended.[94] Because this final rule is merely procedural, no environmental consideration is necessary.

VI. Information Collection Statement

The regulations of the Office of Management and Budget (OMB)[95] require that OMB approve certain information and recordkeeping requirements imposed by an agency. The information collection requirements in this final rule are contained in FERC Form No. 1, "Annual Report of Major public utilities, licensees and others" (OMB approval No. 1902-0021); FERC Form No. 1-F, "Annual Report of Nonmajor public utilities and licensees" (OMB approval No. 1902-0029); FERC Form No. 2, "Annual Report of Major natural gas companies" (OMB approval No. 1902-0028); and FERC Form No. 2-A, "Annual Report of Nonmajor natural gas companies" (OMB approval No. 1902-0030).

The Commission uses the data collected in these annual reports to carry out its audit program and continuous review of the financial conditions of regulated companies. Public utilities and gas companies are required to file these forms annually.

The Commission believes that the final rule will facilitate the Congressional objective of encouraging public utilities to choose the least-cost method of complying with the CAAA's more stringent emission limitation requirements. The dissemination of this information will assist all parties in assessing the costs of implementing alternative compliance strategies. By requiring uniform and consistent accounting and reporting, the final rule will make available to regulatory agencies, public utilities, and the general public, comparable financial and statistical information about allowances established under the CAAA. This information should prove useful in evaluating the cost of compliance with the CAAA, thereby aiding regulatory agencies in their ratemaking activities and promoting an efficient market for allowances, without significantly increasing the reporting burden for public utilities.

The Commission also believes that the addition of new accounting and reporting requirements for regulatory assets and liabilities will provide useful information without significantly increasing the reporting burden for public utilities and gas companies. Regulatory assets and liabilities exist only because of the economic effects of regulation. Regulated entities and the general public have a need for information on the nature of such items

[89] As noted above, Appendix A consists of facsimiles of the revised forms, incorporating the final rule's changes. Appendix A is not being published in the **Federal Register**, but is available from the Commission's Public Reference Room.

[90] 5 U.S.C. 601-12 (1988).

[91] 5 U.S.C. 601(3) (1988) (citing section 3 of the Small Business Act, 15 U.S.C. 632 (1988). Section 3 of the Small Business Act defines a "small-business concern" as a business which is independently owned and operated and which is not dominant in its field of operation 15 U.S.C. 632(a) (1988).

[92] Regulations Implementing National Environmental Policy Act, 52 FR 47897 (Dec. 17, 1987), *FERC Statutes and Regulations, Regulations Preambles 1986-1990* ¶30,783 (1987).

[93] 18 CFR 380.4.

[94] 18 CFR 380.4(a)(2)(ii).

[95] 5 CFR 1320.12.

and will benefit from uniform and consistent accounting and reporting of such items.

Kansas City Power & Light disagrees with the NOPR's statement that the proposed two-step accounting for regulatory assets and liabilities would provide useful information without significantly increasing the reporting burden. Kansas City Power & Light argues that the accounting proposed in the NOPR would require it to hire an additional person to do recordkeeping but that the proposed level of detail would not be useful to the utility or its stockholders

In response, the Commission notes that the final rule does not adopt the NOPR's two-step process. Instead, the accounting for regulatory assets and liabilities adopted in the final rule is simpler and more consistent with past practices than the accounting proposed in the NOPR. Compared to the NOPR, the final rule will reduce the burden of accounting for and reporting regulatory assets and liabilities and should satisfy Kansas City Power & Light's concern. With these changes, the Commission believes even more strongly that the final rule's treatment of regulatory assets and liabilities is justified by the gain in useful information for regulators and the public.

The final rule has been submitted to OMB for its review. Interested persons may obtain information on the information collection requirements of the final rule by contacting the Federal Energy Regulatory Commission, 941 North Capitol Street, NE., Washington, DC 20426 [Attention: Michael Miller, Information Policy and Standards Branch, (202) 208-1415]. Comments on the requirements of the final rule can be sent to the Office of Information and Regulatory Affairs of OMB [Attention: Desk Officer for Federal Energy Regulatory Commission].

VII. Effective Date

This rule is effective January 1, 1993 The information collection provisions, however, will not become effective until approved by OMB.

List of Subjects

18 CFR Part 101

Electric power, Electric utilities, Reporting and recordkeeping requirements, Uniform system of accounts.

18 CFR Part 201

Natural gas, Reporting and recordkeeping requirements, Uniform system of accounts.

By the Commission.

Lois D. Cashell,

Secretary.

[Appendix A omitted in printing.]

Note: This appendix will not be published in the Code of Federal Regulations.

Appendix B—List of Commenters

Allegheny Power System, Inc. (Allegheny Power)

American Electric Power System (AEP)

American Gas Association

American Institute of Certified Public Accountants (AICPA)

American Public Power Association (APPA) *

Arthur Andersen & Co. (Arthur Andersen)

Atlantic City Electric Company (Atlantic Electric)

Baltimore Gas & Electric Company (Baltimore Gas & Electric)

California Public Utilities Commission (California Commission)

Centerior Energy Corporation (Centerior)

Central and South West Corporation (Central & South West)

Chicago Board of Trade

Cincinnati Gas & Electric Company (Cincinnati Gas & Electric)

Columbia Gas Transmission Corporation and Columbia Gulf Transmission Company (Columbia Gas)

Commonwealth Edison Company (Commonwealth Edison)

Consolidated Edison Company of New York, Inc. (Con Edison)

Consumers Power Company (Consumers Power)

Coopers & Lybrand

Delmarva Power & Light Company (Delmarva Power)

Deloitte & Touche

Detroit Edison Company (Detroit Edison)

Duke Power Company (Duke Power)

Edison Electric Institute (EEI)

Environmental Defense Fund

Florida Power & Light Company (Florida Power & Light)

Florida Public Service Commission (Florida Commission)

General Public Utilities Corporation (GPU)

Georgia Public Service Commission (Georgia Commission)

Great Lakes Gas Transmission Limited Partnership

Gulf States Utilities Company (Gulf States) *

IES Industries, Inc. (IES Industries)

Illinois Commerce Commission (Illinois Commission)

Iowa-Illinois Gas and Electric Company (Iowa-Illinois)

Iowa Working Group

Kansas City Power & Light Company (Kansas City Power & Light)

Kentucky Utilities Company (Kentucky Utilities)

KPMG Peat Marwick

Michigan Public Service Commission Staff (Michigan Staff)

Mid-Continent Area Power Pool (MAPP)

National Association of Regulatory Utility Commissioners (NARUC)

National Fuel Gas Supply Corporation (National Fuel Gas)

National Rural Electric Cooperative Association (NRECA)

New York Mercantile Exchange

New York State Department of Public Service (NYDPS)

New York State Electric & Gas Company (NYSEG)

North Carolina Eastern Municipal Power Agency*

(NC Municipal Agency)

North Carolina Utilities Commission Public Staff *

(North Carolina Staff)

Ohio Edison Company (Ohio Edison)

Ohio Public Utilities Commission Staff (Ohio Staff)

Pacific Gas and Electric Company (PG&E)

PacifiCorp

Pennsylvania-New Jersey-Maryland Interconnection members (PJM)

Pennsylvania Power Company (Penn Power)

Pennsylvania Power & Light Company (Pennsylvania Power & Light)

Potomac Electric Power Company (Potomac Electric)

Price Waterhouse

PSI Energy, Inc. (PSI Energy)

Public Service Electric and Gas Company (PSE&G)

Southern California Gas Company

Southern Company

U.S. Department of Energy (Department of Energy)

U.S. Environmental Protection Agency (EPA)

Virginia Electric and Power Company (Virginia Power)

Washington Gas Light Company (Washington Gas)

Wisconsin Electric Power Company (Wisconsin Electric)

Wisconsin Municipal Group

Wisconsin Public Service Corporation (Wisconsin Public Service)

[¶ 30,968]

58 FR 19607 (April 15, 1993)

18 CFR Part 271

[Docket No. RM91-8-002; Order No. 539-B]

Qualifying Certain Tight Formation Gas for Tax Credit

(Issued April 9, 1993)

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Order Granting Requests for Extensions.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is issuing an order which grants the requests of jurisdictional agencies to extend the dead-

* Also filed reply comments.