BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Proposed Rules	**)**	
4 CSR 240-3.162 and	**)**	**Case No. EX-2009-0252**
CSR 240-20.091, Environmental	**)**	
Cost Recovery Mechanisms.	**)**	

COMMENTS OF UNION ELECTRIC COMPANY d/b/a AMERENUE

COMES NOW Union Electric Company d/b/a AmerenUE (AmerenUE or Company), and for its Comments on the proposed rules identified in the caption above, states as follows:

1. On December 31, 2008, the Commission issued its Second Notice of Finding of Necessity to propose two rules relating to the environmental cost recovery mechanism (ECRM) authorized by Senate Bill 179 (SB 179).[1] On that same date, the proposed rules for which the necessity finding was made (proposed as 4 CSR 240-3.162 (Chapter 3 rules) and 4 CSR 240-20.091 (Chapter 20 rules)) were submitted to the Missouri Secretary of State. Notice of the proposed rulemaking for each of the two rules, including notice that a hearing would be held on March 4, 2009 and that comments would be accepted until that date, was published in the *Missouri Register* on February 3, 2009.

2. The proposed rules are nearly identical to rules adopted by the Commission in an earlier rulemaking, Case No. EX-2008-0105 (the Original Rules). The Original Rules were largely supported by AmerenUE, with one technical but important exception – a drafting problem that created an ambiguity in the Original Rules and which remains in part in the proposed rules. We address this drafting problem below.

3. The present rulemaking became necessary due to procedural flaws that occurred in the underlying rulemaking proceeding by which the Original Rules were adopted. The Commission acknowledged these procedural flaws in a Motion for Reversal filed in the Writ of

Review proceeding respecting the Original Rules before the Cole County Circuit Court. Acting on the Motion for Reversal, the circuit court, on December 4, 2008, entered judgment reversing the orders of rulemaking by which the Original Rules were adopted. Thereafter, the Commission acted on the circuit court's judgment by submitting a Rule Action Notice with the Missouri Secretary of State, which provided that the Original Rules were terminated and of no further force and effect concurrently with the effective date of the circuit court's judgment (January 4, 2009).

4. As noted, the proposed rules are nearly identical to the Original Rules, but the proposed rules still contain, in part, the technical but important drafting problem previously raised by AmerenUE in both its Application for Reconsideration filed in the docket respecting the Original Rules (Case No. EX-2008-0105) and in a later Petition to Amend [the Original] Rules (Case No. EX-2009-0071).[2]

5. As explained in AmerenUE's prior filings (Appendices 1 and 2 hereto), this drafting problem deals with a key subject addressed by the proposed rules, that is, the segregation of each utility's pre-existing revenue requirement into "environmental" and "non-environmental" components so that changes in the existing environmental revenue requirement can be tracked through the ECRM mechanism against an environmental revenue requirement established in the rate case where the ECRM is approved.[3] As AmerenUE's Application for Reconsideration in Case No. EX-2008-0105 noted, it appears that when the Commission adopted the Original Rules the Commission intended to adopt substantive language reflecting the workable and practical proposal outlined in comments by AmerenUE witness Mark Birk, which were submitted in Case

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[1] SB 179 is codified as Section 386.266, RSMo. (Cum. Supp. 2008).

[2] The above-referenced Application for Rehearing and Petition to Amend Rules are attached hereto and incorporated herein by this reference as Appendices 1 and 2, respectively.

[3] This is analogous to establishing a base level of fuel costs against which changes are tracked in a fuel adjustment clause mechanism. A key difference, however, is that the environmental revenue requirement includes capital investments that may have been made over many prior years (indeed over decades), which is unlike normalized fuel costs for a recent period.

No. EX-2008-0105.[4] That proposal, which is reflected in the proposed rules, called for the cost related to existing *capital* projects to be included in the "environmental" component of existing rate base only if the capital projects are *major projects* whose *primary purpose* is environmental compliance. Under this proposal, all other environmental costs (those not related to capital projects, like ongoing environmental operating and maintenance expenses) would also be included in the "environmental" revenue requirement.

6. The proposed rules may be intended to reflect this distinction properly, but arguably remain ambiguous on this point. As written, the proposed rules, in Section (1)(F)1 and 2 of the Chapter 3 rules and (1)(D)1 and 2 of the Chapter 20 rules state that the "environmental revenue requirement" shall be comprised of the following:

> "1. All expensed environmental costs that are included in the electric utility's revenue requirement in the general rate proceeding in which the ECRM is established; and
> 2. The costs of any major capital projects whose primary purpose is to permit the electric utility to comply with any federal, state or local environmental law, regulation or rule. Representative examples…."

7. The problem that remains is that since depreciation and taxes associated with capital projects are *expensed* under standard accounting practices, the language in the proposed rules arguably suggests that depreciation and taxes fall under subsection 1, which in turn may lead some to argue that depreciation and taxes for *all* capital projects, not just those that are major projects whose primary purpose is to comply with environmental standards, must be included in the existing "environmental revenue requirement". This argument, if accepted, would mean that depreciation and taxes associated with every environmental capital item, no matter how minor—fans, drains, multipurpose control panels—would have to be identified, calculated and included in the environmental revenue requirement. Segregation of capital items at that level of detail would

[4] Mr. Birk's comments were admitted into the record in Case No. EX-2008-0105 as Hearing Exhibit No. 3, and are attached hereto and incorporated herein by this reference as Appendix 3 hereto. The Company would note that it filed a Reply to Limited Response of Noranda Aluminum, Inc. in Case No. EX-2008-0105, correcting a small part of Mr.

be difficult if not impossible, and requiring such segregation could disable effective use of the proposed rules. This does not appear to be what the Commission intended and, in addition to creating practical problems that could disable the usefulness of the proposed rules, it could lead to complicated, protracted disputes and litigation over whether the environmental revenue requirement has been calculated correctly. Given these concerns and the Commission's clear adoption of the major project/primary purpose concept for existing capital projects, it appears that the intent of the proposed rules is that the capital related costs that must be included in the existing environmental revenue requirement should be only those capital related costs associated with *major items* whose *primary purpose* is environmental compliance. Consequently, it is very important that the proposed rules make clear that in calculating the existing environmental revenue requirement all capital related costs – return, taxes and depreciation –are limited to major projects whose primary purpose is environmental compliance.

8. As just noted, there are three costs associated with environmental capital projects – (a) the cost of capital (return); (b) depreciation; and (c) taxes. It simply makes no sense to treat one capital cost item (return) in one way, in subsection 2 where the major project/primary purpose concept is found, while leaving open the argument that other capital related cost items (depreciation and tax expenses) should be treated differently (and not tied to the major project/primary purposes concept) under subsection 1.

9. The rules may be fixed easily to correct this problem and to remove this ambiguity. All the Commission has to do is modify the proposed rules (in both Chapters 3 and 20) so that they read exactly as previously proposed by AmerenUE in both its above-referenced Application for Reconsideration and in its above-referenced Petition to Amend Rules, as follows:

> "1. All expensed environmental costs *(other than taxes and depreciation associated with capital projects)* that are included in the electric utility's environmental

Birk's comments, which Reply is incorporated herein by this reference.

revenue requirement . . . .

"2. The costs *(i.e. the return, taxes and depreciation)* of any major capital projects ...."

10. This minor change, which resolves the ambiguity that exists in the proposed rules, reflects a workable, common-sense approach to rules that are important to the state and critical to ensuring that utilities can cost-effectively make the huge environmental investments mandated by law. Workable, common-sense rules are important to ensure that customers understand the costs that mandated expenditures to produce a cleaner environment create. For the reasons outlined herein, and to make the rules workable, it is critical that the Commission modify the proposed rules as outlined in these Comments.

WHEREFORE, AmerenUE respectfully submits these Comments in accordance with the Commission's notice of proposed rulemaking published in the *Missouri Register* on February 3, 2009.

Dated March 3, 2009

Respectfully submitted:

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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Proposed Rules	)	
4 CSR 240-3.162 and	)	Case No. EX-2008-0105
4 CSR 240-20.091, Environmental	)	
Cost Recovery Mechanisms.	)	

APPLICATION FOR RECONSIDERATION AND MOTION FOR EXPEDITED TREATMENT

COMES NOW Union Electric Company d/b/a AmerenUE ("Company" or "AmerenUE") and, pursuant to 4 CSR 240-2.160 and 2.080(16), hereby seeks reconsideration of the Orders of Rulemaking respecting 4 CSR 240-3.162 and 4 CR 240-20.091 (the "Orders"), seeks Expedited Treatment, and requests that revised Orders of Rulemaking be issued by March 14, 2008 in order to allow sufficient time to provide revised Orders to the Joint Committee on Administrative Rules ("JCAR") and to timely file revised Orders with the Secretary of State. AmerenUE states as follows in support of this Application and Motion:

1. On January 17, 2008, and pursuant to Section 536.021.2(6), RSMo.,[1] the Commission held a hearing respecting proposed rules which are the subject of the Orders.

2. On March 3, 2008, pursuant to Section 536.024.3, RSMo., the Commission submitted the Orders to the Joint Committee on Administrative Rules. The Commission filed the Orders in this docket on March 5, 2008. Section 536.024, RSMo. prohibits the Commission from filing the Orders with the Secretary of State until April 3, 2008.[2] Pursuant to Section 536.021.8, RSMo, the rules reflected in the Orders shall not take effect until the thirtieth day after the rules are published in the *Code of State Regulations.* Consequently, the rules reflected in the Orders are not yet effective as a matter of law.

[1] Statutory references are to the Revised Statutes of Missouri (Cum. Supp. 2007), unless otherwise noted.
[2] Because the hearing occurred on January 17, 2008, the rules must be submitted to the Secretary of State by April 16, 2008, which is 90 days after the hearing date. *See* Section 536.021.5, RSMo.

3. A key subject addressed by the Commission's rule is the segregation of the utility's pre-existing rate base into "environmental" and "non-environmental" components. AmerenUE believes that the Commission intended to substantively adopt an alternative proposal submitted by AmerenUE in comments by Mark Birk, which provided that the cost of existing *capital* projects should be included in the "environmental" component of existing rate base only if the capital projects are major projects whose primary purpose is environmental compliance.[3] Under this proposal, all other environmental expenses (i.e. those not related to capital projects) would also be included in the "environmental" rate base.

4. Unfortunately, the language in the final rule does not reflect this distinction properly. Section (1)(F)(1) and (2) of the Chapter 3 rules and (1)(D)(1) of the Chapter 20 rules state that the "environmental revenue requirement" shall be comprised of the following:

> 1. All expensed environmental costs that are included in the electric utility's revenue requirement in the general rate proceeding in which the ECRM is established; and
> 2. The required return on costs of any major capital projects whose primary purpose is to permit the electric utility to comply with any federal, state or local environmental law, regulation or rule. Representative examples….

5. The problem with the above-quoted language is that since depreciation and taxes are expensed under applicable financial and regulatory accounting rules and practices, under the language in the rule these items would have to be included in the "environmental revenue requirement" for *all* capital projects that arguably have some relationship to environmental compliance, not just those that are *major* projects whose *primary purpose* is to comply with environmental laws or regulations. This means that depreciation and taxes associated with every capital item that arguably has some relationship to environmental compliance, no matter how

[3] AmerenUE still has concerns with the real potential for disputes relating to the process of segregating the rate base into "environmental" and "nonenvironmental" categories at all. However, the alternative proposal is materially better than the virtually impossible task of conducting a *total* segregation of the rate base into "environmental" and "nonenvironmental" components.

minor— pipes, smokestacks, control panels, fans, drains, etc. —will have to be calculated and included in the environmental revenue requirement. Surely this is not what the Commission intended. Rather, it seems apparent that the Commission intended the costs associated with capital items to be limited to major items whose primary purpose is environmental compliance. This is evidenced by the fact that the Commission adopted the major project/primary purpose concept with respect to the cost of capital – the return – associated with environmental capital projects. There are three costs associated with environmental capital projects – the cost of capital (return), and depreciation and taxes. It makes no sense to treat one cost (return) in one way, while treating the other two costs differently.

6. The rule may be fixed easily and simply to reflect what the Commission intended. All the Commission has to do is add the italicized language to the above-referenced sections that list the items that comprise the environmental revenue requirement:

> 1. All expensed environmental costs that are included in the electric utility's revenue requirement *(other than taxes and depreciation associated with capital projects)* in the general rate proceeding in which the ECRM is established; and
> 2. The [delete "required return on"] costs of any major capital projects *(i.e. the return, taxes and depreciation)* associated with projects whose primary purpose is to permit the electric utility to comply with any federal, state or local environmental law, regulation or rule. Representative examples….

7. Because the rules are not effective, and indeed cannot be effective for several weeks as outlined above, reconsideration of the Orders is proper under 4 CSR 240-2.160(2). Consequently, the Commission should reconsider the intent of its Orders and issue revised final Orders of Rulemaking reflecting the fact that the Commission did not intend to require a total segregation of all rate base into "environmental" and "non-environmental" categories. That intent would be made clear by adoption of the language provided for in paragraph 6 of this Application.

8. The Commission may be concerned with the timing of reconsidering the Orders and of complying with Sections 536.024.3 and 536.021.5, RSMo. So long as the Commission makes this correction and submits revised final orders of rulemaking to JCAR no later than this Friday, March 14, JCAR's 30-day review period will expire in time to file the revised Orders with the Secretary of State by April 16.

9. ECRM rules that at least provide some reasonable opportunity to be useful and workable in practice are important to the state and critical to ensuring that utilities can cost-effectively make the huge environmental investments mandated by law, principally federal law, which also generate other operating costs. Such rules are important to ensure that customers understand the costs that mandated expenditures to produce a cleaner environment create. To provide a set of ECRM rules that provide a reasonable opportunity to be useful and workable, it is critical that the Commission reconsider its Orders and revise them as outlined in this Application.

10. This Application and Motion were filed as soon as possible under the circumstances. The Orders were filed in the Data Center and posted on EFIS on March 5, just 4 business days ago. Moreover, there was no service of the Orders on the Company.[4] By acting by March 14, the Commission avoids the harm of adopting rules that fail to reflect its intent and allows itself time to provide revised Orders to JCAR and, upon the expiration of the 30-day JCAR review period, to file the final Orders with the Secretary of State by April 16.

WHEREFORE, the Company prays that the Commission correct its Orders of Rulemaking as outlined hearing, that it do so by March 14, that it submit the corrected Orders to JCAR by March 14, and that it then submit the final corrected Orders to the Secretary of State by April 16, 2008.

[4] Service was not required by Chapter 536, RSMo., and is mentioned here simply to point out that the Company filed this Application and Motion quickly after the Orders were actually filed in EFIS.

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ATTORNEYS FOR UNION ELECTRIC COMPANY d/b/a AMERENUE

Dated: March 11, 2008

**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI**

In the Matter of A Proposed	)	
Amendment to 4 CSR 240-3.162 and	)	Case No. EX-2009-____
20.091, Environmental	)	
Cost Recovery Mechanisms.	)	

PETITION TO AMEND RULES

COMES NOW Union Electric Company d/b/a AmerenUE ("Company" or "AmerenUE") and, pursuant to §536.041, RSMo.[1] and 4 CSR 240-2.180, hereby petitions the Commission to amend §(1)(F)(1) and (2) of 4 CSR 240-3.162 and §(1)(D)(1) of 4 CSR 250-20.091. In support of its Petition, AmerenUE states as follows:

Reasons In Support of the Amendment[2]

1. On March 3, 2008, pursuant to §536.024.3, RSMo. (Cum. Supp. 2007), the Commission submitted Final Orders of Rulemaking for 4 CSR 240-3.162 and 4 CSR 240-20.091to the Joint Committee on Administrative Rules. The Final Orders of Rulemaking were submitted to the Secretary of State on April 3, 2008, were published in the *Code of State Regulations* on May 31, 2008, and became effective pursuant to § 536.021.8, RSMo. (Cum. Supp. 2007) on June 30, 2008.

2. On March 11, 2008, the Company filed an Application for Reconsideration respecting the rules with the Commission because of a technical drafting problem the Company believes was made when the final rule language was adopted at the Commission's February 29, 2008 Agenda meeting.[3] This error dealt with a key subject addressed by the rules, being the

[1] Statutory references are to the Revised Statutes of Missouri (2000), unless otherwise noted.
[2] *See* 4 CSR 240-2.180(3)3.

[3] The full text of the rules sought to be amended, including the suggested amendments, are attached hereto as Exhibit A and incorporated herein by this reference. *See* 4 CSR 240-2.180(3)2.

segregation of each utility's pre-existing revenue requirement into "environmental" and "non-environmental" components. While the Commission denied the Company's Application for Reconsideration (apparently largely because of timing concerns given the timing requirements of § 536.021, RSMo. (Cum Supp. 2007)), the Commission's discussion relating to its denial of the Company's Application, and other facts as discussed herein, suggest that the rules as adopted do not reflect the collective intent of the Commission with respect to this rate base segregation issue. Just as importantly, the rules as adopted result in rules that may not be workable or practical to apply. As AmerenUE's Application for Reconsideration noted, it appears that the Commission intended to substantively adopt a workable and practical proposal submitted by AmerenUE in comments by Mark Birk. That proposal called for the cost of existing *capital* projects to be included in the "environmental" component of existing rate base only if the capital projects are *major projects whose primary purpose is environmental compliance*. Under this proposal, all other environmental expenses (i.e. those not related to capital projects) would also be included in the "environmental" revenue requirement.

3. Unfortunately, the rules do not reflect this distinction properly. Section (1)(F)(1) and (2) of the Chapter 3 rules and (1)(D)(1) of the Chapter 20 rules state that the "environmental revenue requirement" shall be comprised of the following:

> "1. All expensed environmental costs that are included in the electric utility's revenue requirement in the general rate proceeding in which the ECRM is established; and
> 2. The required return on costs of any major capital projects whose primary purpose is to permit the electric utility to comply with any federal, state or local environmental law, regulation or rule. Representative examples…."

4. The problem is that since depreciation and taxes associated with capital projects are expensed, under the language in the rules these items may arguably have to be included in the "environmental revenue requirement" for all capital projects, not just those that are major

projects whose primary purpose is to comply with environmental standards. This means that depreciation and taxes associated with every environmental capital item, no matter how minor—fans, drains, multipurpose control panels—may arguably have to be calculated and included in the environmental revenue requirement. This does not appear to be what the Commission intended. Rather, it appears much more likely that the Commission intended the costs associated with capital items to be limited to major items whose primary purpose is environmental compliance. This is evidenced by the fact that the Commission adopted the major project/primary purpose concept with respect to the cost of capital – the return – associated with environmental capital projects. There are three costs associated with environmental capital projects – the cost of capital (return), depreciation and taxes. It makes no sense to treat one cost (return) in one way, while treating the other two costs differently.

5. The rules may be fixed easily and simply to correct this problem. All the Commission has to do is amend the rules, as it is authorized to do by §536.041, RSMo., by adding the italicized language to the above-referenced sections that list the items that comprise the environmental revenue requirement:

> "1. All expensed environmental costs *(other than taxes and depreciation associated with capital projects)* that are included in the electric utility's environmental revenue requirement . . .
> 2. The [delete "required return on"] costs *(i.e. the return, taxes and depreciation)* of of any major capital projects . . .

6. Workable, common-sense rules are important to the state and critical to ensuring that utilities, including the Company, can cost-effectively make the huge environmental investments mandated by law, principally federal law, which also generate other operating costs. Workable, common-sense rules are important to ensure that customers understand the costs that

mandated expenditures to produce a cleaner environment create. To make the rules workable, it is critical that the Commission amend the rules as outlined in this Petition.

Miscelleneous Filing Requirements

7. Petitioner's name, street address and mailing address are as follows:

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8. Copies of pleadings, correspondence or other materials relating to this Petition should also be served on the undersigned counsel as follows:

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9. Petitioner estimates that the proposed amendment will not cost private entities, state agencies or political subdivisions more than $500 in the aggregate.

Requested Relief

10. In order to amend the rule as requested herein, §536.021, RSMo. (Cum. Supp. 2007) and 4 CSR 240-2.180(4) require the Commission to issue a notice of proposed rulemaking. The Commission has the option of requesting statements in support of or in opposition to the amendment (i.e., comments) or can seek both comments and hold a hearing. Within 90 days after the end of a written comment period or the end of any hearing the Commission chooses to conduct,

the Commission must issue an order or rulemaking that (a) adopts the proposed amendment without further change, (b) adopts the proposed amendment with further changes, or (c) withdraws the proposed amendment. In accordance with those requirements, the Company hereby requests that the Commission (i) issue its notice of proposed rulemaking containing the rules, as they are proposed to be amended herein; (ii) include in its notice of proposed rulemaking instructions for filing statements in support of or in opposition to the proposed amendments 30 days after the notice of proposed rulemaking is published in the *Missouri Register*; and (iii) after consideration of those statements in accordance with law, issue its final order of rulemaking adopting the proposed amendments without further change.

Respectfully Submitted,

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Dated: August 29, 2008

CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing Petition to Amend Rules was served via electronic mail (e-mail) or via regular mail on this 29th day of August, 2008, on:

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/s/ James B. Lowery

EXHIBIT A to Petition to Amend Rules

4 CSR 240-3.162 Electric Utility Environmental Cost Recovery Mechanisms Filing and Submission Requirements

PURPOSE: This rule implements the provisions of Senate Bill 179, codified at section 386.266, RSMo Supp. 2007, which permits the commission to authorize the inclusion of an environmental cost recovery mechanism in utility rates.

(1) As used in this rule, the following terms mean:
(A) EFIS means the electronic filing and information system of the commission;
(B) Electric utility means electrical corporation as defined in section 386.020, RSMo, subject to commission regulation pursuant to Chapters 386 and 393, RSMo;
(C) Environmental compliance plan means a twenty (20)-year forecast of environmental compliance investments and a detailed four (4)-year plan for complying with federal, state, and local environmental laws, regulations and rules. The four (4)-year plan will include plans to use emission allowances for compliance, plans for emission allowance transactions and, on a generation unit basis, plans for investments in emission control equipment. The environmental compliance plan shall be consistent with the implementation plan of the most recent resource plan filing except as otherwise explained by the electric utility. Approval of an Environmental Cost Recovery Mechanism (ECRM) does not imply approval or predetermination of prudence of the environmental compliance plan;
(D) Environmental Cost Recovery Mechanism (ECRM) means a mechanism established in a general rate proceeding that allows periodic rate adjustments, outside a general rate proceeding, to reflect the net increases or decreases in an electric utility's environmental revenue requirement, plus additional environmental costs incurred since the prior general rate proceeding.
(E) Environmental costs means prudently incurred costs, both capital and expense, directly related to compliance with any federal, state, or local environmental law, regulation or rule.
1. Environmental costs do not include fuel and purchased power costs as defined in 4 CSR 240-3.161(1)(A).
2. Prudently incurred costs do not include any increased costs resulting from negligent or wrongful acts or omissions by the utility;
(F) The environmental revenue requirement shall be comprised of the following:
1. All expensed environmental costs **(other than taxes and depreciation associated with capital projects)** that are included in the electric utility's revenue requirement in the general rate proceeding in which the ECRM is established; and
2. The ~~required return on~~ costs **(i.e., the return, taxes and depreciation)** of any major capital projects whose primary purpose is to permit the electric utility to comply with any federal, state or local environmental law, regulation or rule. Representative examples of such capital projects to be included (as of the date of adoption of this rule) are electrostatic precipitators, fabric filters, nitrous oxide emissions control equipment and flue gas desulfurization equipment. The costs of such capital projects shall be those identified on the electric utility's books and records as of the last day of the test year, as updated. utilized in the general rate proceeding in which the ECRM is established.
(G) General rate proceeding means a general rate increase proceeding or complaint proceeding

before the commission in which all relevant factors that may affect the costs, or rates and charges of the electric utility are considered by the commission; and

(H) Rate class is a customer class defined in an electric utility's tariff. Generally, rate classes include Residential, Small General Service, Large General Service and Large Power Service, but may include additional rate classes. Each rate class includes all customers served under all variations of the rate schedules available to that class.

(2) When an electric utility files to establish an ECRM as described in 4 CSR 240-20.091(2), the electric utility shall file the following supporting information as part of or in addition to, its direct testimony:

(A) An example of the notice to be provided to customers as required by 4 CSR 240-20.091(2)(E);

(B) An example customer bill showing how the proposed ECRM shall be separately identified on affected customers' bills in accordance with 4 CSR 240-20.091(8);

(C) Proposed ECRM rate schedules;

(D) A general description of the design and intended operation of the proposed ECRM;

(E) A complete explanation of how the proposed ECRM is reasonably designed to provide the electric utility a sufficient opportunity to earn a fair return on equity;

(F) A complete explanation of how the proposed ECRM shall be trued-up to reflect over- or under-collection on at least an annual basis;

(G) A complete description of how the proposed ECRM is compatible with the requirement for prudence reviews;

(H) A complete explanation of all the costs that shall be considered for recovery under the proposed ECRM and the specific account used for each cost item on the electric utility's books and records;

(I) A complete explanation of all of the costs, both capital and expense, incurred to comply with any current federal, state, or local environmental law, regulation or role that the electric utility is proposing be included in base rates and the specific account used for each cost item on the electric utility's books and records;

(J) A complete explanation of all the revenues that shall be considered in the determination of the amount eligible for recovery under the proposed ECRM and the specific account where each such revenue item is recorded on the electric utility's books and records;

(K) A complete explanation of any feature designed into the proposed ECRM or any existing electric utility policy, procedure, or practice that can be relied upon to ensure that only prudent costs shall be eligible for recovery under the proposed ECRM;

(L) For each of the major categories of costs, that the electric utility seeks to recover through its proposed ECRM, a complete explanation of the specific rate class cost allocations and rate design used to calculate the proposed environmental revenue requirement and any subsequent ECRM rate adjustments during the term of the proposed ECRM;

(M) A complete explanation of any change in business risk to the electric utility resulting from implementation of the proposed ECRM in setting the electric utility's allowed return in any rate proceeding, in addition to any other changes in business risk experienced by the electric utility.

(N) The electric utility's environmental compliance plan including a complete description of—

1. The electric utility's long-term environmental compliance planning process;
2. The analysis performed to develop the electric utility's environmental compliance plan; and
3. If the environmental compliance plan is inconsistent with the electric utility's most recent resource plan filing, a detailed explanation of why such inconsistencies exist;

and

(O) Authorization for the commission staff to release the previous five (5) years of historical surveillance reports submitted to the commission staff by the electric utility to all parties to the case.

(3) When an electric utility files a general rate proceeding following the general rate proceeding that established its ECRM as described by 4 CSR 240-20.091(2) in which it requests that its ECRM be continued or modified, the electric utility shall file with the commission and serve parties, as provided in sections (9) through (11) in this rule, the following supporting information as part of, or in addition, to, its direct testimony.

(A) an example of the notice to be provided to customers as required by 4 CSR 240-20.091(2)(E);

(B) If the electric utility proposes to change the identification of the ECRM on the customer's bill, an example customer bill showing how the proposed ECRM shall be separately identified on affected customers' bills, including the proposed language, in accordance with 4 CSR 240-20.091(8);

(C) Proposed ECRM rate schedules;

(D) A general description of the design and intended operation of the proposed ECRM;

(E) A complete explanation of how the proposed ECRM is reasonably designed to provide the electric utility a sufficient opportunity to earn a fair return on equity;

(F) A complete explanation of how the proposed ECRM shall be trued-up to reflect over- or under-collections on at least an annual basis;

(G) A complete description of how the proposed ECRM is compatible with the requirement for prudence reviews;

(H) A complete explanation of all the costs that shall be considered for recovery under the proposed ECRM and the specific account used for each cost item on the electric utility's books and records;

(I) A complete explanation of all of the costs, both capital and expense, incurred to comply with any current federal, state, or local environmental law, regulation or rule that the electric utility is proposing be included in base rates and the specific account used for each cost item on the electric utility's books and records;

(J) A complete explanation of all the revenues that shall be considered in the determination of the amount eligible for recovery under the proposed ECRM and the specific account where each such revenue item is recorded on the electric utility's books and records;

(K) A complete explanation of any feature designed into the proposed ECRM or any existing electric utility policy, procedure, or practice that can be relied upon to ensure that only prudent costs shall be eligible for recovery under the proposed ECRM;

(L) For each of the major categories of cost, that the electric utility seeks to recover through its proposed ECRM, a complete explanation of the specific rate class cost allocations and rate design used to calculate the proposed environmental revenue requirement and any subsequent ECRM rate adjustments during the term of the proposed ECRM;

(M) A complete explanation of any change in business risk to the electric utility resulting from implementation of the proposed ECRM in setting the electric utility's allowed return in any rate proceeding, in addition to any other changes in business risk experienced by the electric utility;

(N) A description of how responses to subsections (3)(B) through (M) differ from responses to subsections (3)(B) through (M) for the currently approved ECRM.

(O) The electric utility's environmental compliance plan including a complete description of—

1. The electric utility's long-term environmental compliance planning process;
2. The analysis performed to develop the electric utility's environmental compliance plan; and

3. If the environmental compliance plan is inconsistent with the electric utility's most recent resource plan filing, a detailed explanation of why such inconsistencies exist; and

(P) Any additional information that may have been ordered by the commission in the prior general rate proceeding to be provided.

(4) When an electric utility files a general rate proceeding following the general rate proceeding that established its ECRM as described in 4 CSR 240-20.091(3) in which it requests that its ECRM be discontinued, the electric utility shall file with the commission and serve parties, as provided in sections (9) through (11) in this rule, the following supporting information as part of, or in addition to, its direct testimony;

(A) An example of the notice to be provided to customers as required by 4 CSR 240-20.091(3)(B);

(B) The periodic adjustment shall reflect a comprehensive measurement of both increases and decreases to the environmental revenue requirement established in the prior general rate proceeding plus the additional environmental costs incurred since the prior general rate proceeding.

(C) A complete explanation of why the ECRM is no longer necessary to provide the electric utility a sufficient opportunity to earn a fair return on equity;

(D) A complete explanation of any change in business risk to the electric utility resulting from discontinuation of the ECRM in setting the electric utility's allowed return, in addition to any other changes in business risk experienced by the electric utility; and

(E) Any additional information that may have been ordered by the commission in the prior general rate proceeding to be provided.

(5) Each electric utility with an ECRM shall submit, with an affidavit attesting to the veracity of the information, the following information on a monthly basis to the manager of the auditing department of the commission, the Office of the Public Counsel (OPC) and others, as provided in sections (9) through (11) in this rule. The information may be submitted to the manager of the auditing department through EFIS. The following information shall be aggregated by month and supplied no later than sixty (60) days after the end of each month when the ECRM is in effect. The first submission shall be made within sixty (60) days after the end of the first complete month after the ECRM goes into effect. It shall contain, at a minimum:

(A) The revenues billed pursuant to the ECRM by rate class and voltage level, as applicable;

(B) The revenues billed through the electric utility's base rate allowance by rate class and voltage level;

(C) All significant factors that have affected the level of ECRM revenues along with workpapers documenting these significant factors;

(D) The difference, by rate class and voltage level, as applicable, between the total billed ECRM revenues and the projected ECRM revenues;

(E) Any additional information ordered by the commission to be provided; and

(F) To the extent any of the requested information outlined above is provided in response to another section, the information only needs to be provided once.

(6) Each electric utility with an ECRM shall submit, with an affidavit attesting to the veracity of the information, a Surveillance Monitoring Report, which shall be treated as highly confidential, as required in 4 CSR 240-20.091(9) to the manager of the auditing department of the commission, OPC and others as provided in sections (9) through (11) in this rule. The information may be submitted to the manager of the auditing department through EFIS.

(A) There are five (5) parts to the electric utility Surveillance Monitoring Report. Each part, except Part One, Rate Base Quantifications, shall contain information for the last twelve (12)-month period and the last quarter data for total company electric operations and Missouri jurisdictional operations. Page one, Rate Base Quantifications shall contain only information for the ending date of the period being reported. The form of the Surveillance Monitoring Report form is included herein.

1. Rate Base Quantifications Report. The quantification of rate base items on page one shall be consistent with the methods or procedures used in the most recent rate proceeding unless otherwise specified. The report shall consist of specific rate base quantifications of:
   - A. Plant in service;
   - B. Reserve for depreciation;
   - C. Materials and supplies;
   - D. Cash working capital;
   - E. Fuel inventory;
   - F. Prepayments;
   - G. Other regulatory assets;
   - H. Customer advances;
   - I. Customer deposits;
   - J. Accumulated deferred income taxes;
   - K. Any other item included in the utility's rate base in the most recent rate proceeding;
   - L. Net Operating Income from page three; and
   - M. Calculations of the overall return on rate base.
2. Capitalization Quantifications Report. Page two shall consist of specific capitalization quantifications of:
   - A. Common stock equity (net);
   - B. Preferred stock (par or stated value outstanding);
   - C. Long-term debt (including current maturities);
   - D. Short-term debt; and
   - E. Weighted cost of capital including component costs.
3. Income Statement. Page three shall consist of an income statement containing specific quantification of:
   - A. Operating revenues to include sales to industrial, commercial and residential customers, sales for resale and other components of total operating revenues;
   - B. Operating and maintenance expenses for fuel expense, production expenses, purchased power energy and capacity;
   - C. Transmission expenses;
   - D. Distribution expenses;
   - E. Customer accounts expenses;
   - F. Customer service and information expenses;
   - G. Sales expenses;
   - H. Administrative and general expenses;
   - I. Depreciation, amortization and decommissioning expense;
   - J. Taxes other than income taxes;
   - K. Income taxes; and
   - L. Quantification of heating degree and cooling degree days, actual and normal.
4. Jurisdictional Allocation Factor Report. Page four shall consist of a listing of jurisdictional allocation factors for the rate base, capitalization quantification reports and income statement.
5. Financial Data Notes. Page five shall consist of notes to financial data including, but not limited to:

A. Out-of-period adjustments;
B. Specific quantification of material variances between actual and budget financial performance;
C. Material variances between current twelve (12)-month period and prior twelve (12)-month revenue;
D. Expense level of items ordered by the commission to be tracked pursuant to the order establishing the ECRM;
E. Budgeted capital projects;
F. Events that materially affect debt or equity surveillance components; and
G. All settlements in regards to environmental compliance causing the electric utility to incur expenses or make investments in excess of one hundred thousand dollars ($100,000) or fines against the electric utility in regards to environmental compliance greater than one hundred thousand dollars ($100,000).

(B) The Surveillance Monitoring Report shall contain any additional information ordered by the commission to be provided.

(C) The electric utility shall annually submit its approved budget, in electronic form, based upon its budget year in a format similar to the Surveillance Monitoring Report. The budget submission shall provide a quarterly and annual quantification of the electric utility's income statement. The budget shall be submitted within thirty (30) days of its approval by the electric utility's management or within sixty (60) days of the beginning of the electric utility's fiscal year, whichever is earliest. The budget submission shall be treated as highly confidential pursuant to 4 CSR 240-2.135.

(D) If the electric utility has a rate adjustment mechanism as defined in 4 CSR 240-20.090(1)(G), the surveillance report submitted by the electric utility as required by 4 CSR 240-3.161(6) along with information submitted in response to (6)(A)5.G of this subsection shall meet the surveillance reporting required by this section.

(7) When an electric utility files tariff schedules to adjust an ECRM rate as described in 4 CSR 240-20.091(4) with the commission, and serves upon parties as provided in sections (9) through (11) in this rule, the tariff schedules must be accompanied by supporting testimony, and at least the following supporting information:

(A) The following information shall be included with the filing:

1. For the period from which historical costs are used to adjust the ECRM rate:
   A. Emission allowance costs differentiated by purchases, swaps, and loans;
   B. Net revenues from emission allowance sales, swaps, and loans;
   C. Extraordinary costs not to be passed through, if any, due to such costs being an insured loss, or subject to reduction due to litigation, or for any other reason.
   D. Base rate component of environmental compliance costs and revenues;
   E. Identification of capital projects placed in service that were not anticipated in the previous general rate proceeding; and
   F. Any additional requirements ordered by the commission in the prior general rate proceeding;
2. The levels of environmental capital costs and expenses in the base rate revenue requirement from the prior general rate proceeding;
3. The levels of environmental capital cost in the base rate revenue requirement from the prior general rate proceeding as adjusted for the proposed date of the periodic adjustment;
4. The capital structure as determined in the prior general rate proceeding.
5. The cost rates for the electric utility's debt and preferred stock as determined in the prior

general rate proceeding;

6. The electric utility's cost of common equity as determined in the prior general rate proceeding;
7. Calculation of the proposed ECRM collection rates; and
8. Calculations underlying any seasonal variation in the ECRM collection rates; and

(B) Workpapers supporting all items in subsection (7)(A) shall be submitted to the manager of the auditing department, and served upon parties as provided in sections (9) through (11) in this rule. The workpapers may be submitted to the manager of the auditing department through EFIS.

(8) When an electric utility that has an ECRM files its application containing its annual true-up with the commission, as described in 4 CSR 240-20.091(5), any rate schedule filing must be accompanied by supporting testimony, and the electric utility shall:

(A) File the following information with the commission and serve upon parties as provided in sections (9) through (11) in this rule:

1. Amount of costs that it has over-collected or under-collected through ECRM by rate class and voltage level, as applicable;
2. Proposed adjustments or refunds by rate class and voltage level as applicable;
3. Electric utility's short-term borrowing rate; and
4. Any additional information ordered by the commission;

(B) Submit the following information to the manager of the auditing department and serve upon the parties as provided in sections (9) through (11) in this rule. The information may be submitted to the manager of the auditing department through EFIC.

1. Workpapers detailing how the determination of the over-collection or under-collection of costs through the ECRM was made including any model inputs and outputs and the derivation of any model inputs.
2. Workpapers detailing the proposed adjustments or refunds.
3. Basis for the electric utility's short-term borrowing rate.
4. Any additional information ordered by the commission to be provided.

(9) Providing to other parties items required to be filed or submitted in preceding sections (3) through (8). Information required to be filed with the commission or submitted to the manager of the auditing department of the commission and to OPC in sections (3) through (8) shall also be, in the same format, served on or submitted to any party to the related general rate proceeding in which the ECRM was approved by the commission, periodic adjustment proceeding, annual true-up, prudence review, or general rate case to modify, extend or discontinue the same ECRM, pursuant to the procedures in 4 CSR 240-2.135 for handling confidential information, including any commission order issued thereunder.

(10) Party status and providing to other parties affidavits, testimony, information, reports and workpapers in related proceedings subsequent to general rate proceeding establishing ECRM.

(A) A person or entity granted intervention in a general rate proceeding in which an ECRM is approved by the commission, shall be a party to any subsequent related periodic adjustment proceeding, annual true-up or prudence review, without the necessity of applying to the commission for intervention. In any subsequent general rate proceeding, such person or entity must seek and be granted status as an intervenor to be a party to that case. Affidavits, testimony, information, reports, and workpapers to be filed or submitted in connection with a subsequent related periodic adjustment proceeding, annual true-up, prudence review, or general rate case to modify, extend or discontinue the same ECRM shall be served on or submitted to all parties from the prior related general rate proceeding and on all parties from any subsequent related periodic adjustment proceeding, annual true-up, prudence review, or general rate case to modify, extend or discontinue the same ECRM, concurrently with filing the same with the commission or submitting the same to the manager of the auditing department of the commission and OPC, pursuant to the procedures in 4 CSR 240-2.135 for handling confidential information, including any commission order issued thereunder.

(B) A person or entity not a party to the general rate proceeding in which an ECRM is approved by the commission may timely apply to the commission for intervention, pursuant to 4 CSR 240-2.075(2) through (4) of the commission's rule on intervention, respecting any related subsequent periodic adjustment proceeding, annual true-up, or prudence review, or, pursuant to 4 CSR 240-2.075(1) through (5), respecting any subsequent general rate case to modify, extend or discontinue the same ECRM. If no party to a subsequent periodic adjustment proceeding, annual true-up, or prudence review, objects within ten (10) days of the filing of an application for intervention, the applicant shall be deemed as having been granted intervention without a specific commission order granting intervention, unless within the above-referenced ten (10)-day period the commission denies the application for intervention on its own motion. If an objection to the application for intervention is filed on or before the end of the above-referenced ten (10)-day period, the commission shall rule on the application and the objection within ten (10) days of the filing of the objection.

(11) Discovery. The results of discovery from a general rate proceeding where the commission may approve, modify, reject, extend or discontinue an ECRM, or from any subsequent periodic adjustment proceeding, annual true-up, or prudence review relating to the same ECRM, may be used without a party resubmitting the same discovery requests (data requests, interrogatories, requests for production, requests for admission, or depositions) in the subsequent proceeding to parties that produced the discovery in the prior proceeding, subject to a ruling by the commission concerning any evidentiary objection made in the subsequent proceeding.

(12) Supplementing and updating data requests in subsequent related proceedings. If a party which submitted data requests relating to a proposed ECRM in the general rate proceeding where the ECRM was established or in the general rate proceeding where the same ECRM was modified or extended, or in any subsequent related periodic adjustment proceeding, annual true-up, or prudence review wants the responding party to whom the prior data requests were submitted to supplement or update that responding party's prior responses for possible use in a subsequent related periodic adjustment proceeding, annual true-up, prudence review or general rate case to modify, extend or discontinue the same ECRM, the party which previously submitted the data requests shall submit an additional data request to the responding party to whom the data requests were previously submitted which clearly identifies the particular data requests to be supplemented or updated and the particular period to be covered by the updated response. A responding party to a request to supplement or update shall supplement or update a data request response from: a related general rate proceeding where a ECRM was established; a general rate case where the same ECRM was modified or extended; or a related periodic adjustment proceeding, annual true-up, or prudence review, which the responding party has learned or subsequently learns is in some material respect incomplete or incorrect.

(13) Separate cases for each general rate proceeding involving an ECRM and for each mutually exclusive twelve (12)-month annual true-up period of an ECRM. Each general rate proceeding where the commission may approve, modify, or reject an ECRM; each general rate case where the commission may authorize the modification, extension, or discontinuance of an ECRM; and each mutually exclusive twelve (12)-month period of an ECRM that encompasses an annual true-up, prudence review, and possible periodic adjustments shall comprise a separate case.

The same procedures for handling confidential information shall apply, pursuant to 4 CSR 240-2.135, as in the immediately preceding ECRM case for the particular electric utility, unless otherwise directed by the commission on its own motion or as requests by a party and directed by the commission.

(14) New ECRM For the purposes of this rule, an ECRM, if continued, modified or extended in a general rate case, even in substantially the form approved in the prior general rate proceeding, shall be considered to be a new district ECRM after each general rate proceeding required by section 386.266.4(3), RSMo.

(15) Right to Discovery Unaffected. In addressing certain discovery matters and the provision of certain information by electric utilities, this rule is not intended to restrict the discovery rights of any party.

(16) Waivers. Provisions of this rule may be waived by the commission for good cause shown.

(17) Rule Review. The commission shall review the effectiveness of this rule by no later than December 31, 2011, and may, if it deems necessary, initiate rulemaking proceedings to revise this rule.

AUTHORITY: sections 386.250 and 393.140, RSMo 2000, and 386.266, RSMo Supp. 2005. Original rule filed June 16, 2006, effective Jan. 30, 2007.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; 386.266 RSMo 2005 and 393.140, RSMo 1939, amended 1949, 1967.*

4 CSR 240-20.091 Electric Utility Environmental Cost Recovery Mechanisms

PURPOSE: This rule allows the establishment of an Environmental Cost Recovery Mechanism, which allows periodic rate adjustments to reflect net increases or decreases in an electric utility's prudently incurred costs directly related to compliance with any federal, state, or local environmental law, regulation or *rule.*

(1) Definitions. As used in this rule, the following terms mean as follows:

(A) Electric utility means electrical corporation as defined in section 386.020, RSMo subject to commission regulation pursuant to Chapters 386 and 393, RSMo;

(B) Environmental Cost Recovery Mechanism (ECRM) means a mechanism established in a general rate proceeding that allows periodic rate adjustments, outside a general rate proceeding, to reflect the net increases or decreases in an electric utility's incurred environmental costs;

(C) Environmental costs means prudently incurred costs, both capital and expense, directly related to compliance with any federal, state, or local environmental law, regulation or rule.

1. Environmental costs do not include fuel and purchased power costs as defined in 4 CSR 240-20.090(1)(B).
2. Prudently incurred costs do not include any increased costs resulting from negligent or wrongful acts or omissions by the utility;

(D) The environmental revenue requirement shall be comprised of the following:

1. All expensed environmental costs **(other than taxes and depreciation associated with capital projects)** that are included in the electric utility's revenue requirement in the general rate proceeding in which the ECRM is established; and
2. The ~~required return on~~ costs **(i.e., the return, taxes and depreciation)** of any major capital projects whose primary purpose is to permit the electric utility to comply with any federal, state or local environmental law, regulation or rule. Representative examples of such capital projects to be included (as of the date of adoption of this rule) are electrostatic precipitators. fabric filters, nitrous oxide emissions control equipment and flue gas desulfurization equipment. The costs of such capital projects shall be those identified on the electric utility's books and records as of the last day of the test year, as updated, utilized in the general rate proceeding in which the ECRM is established.

(E) General rate proceeding means a general rate increase proceeding or complaint proceeding before the commission in which all relevant factors that may affect the costs, or rates and charges of the electric utility are considered by the commission;

(F) Rate class is a customer class as defined in an electric utility's tariff. Generally, rate classes include Residential, Small General Service, Large General Service and Large Power Service, but may include additional rate classes. Each rate class includes all customers served under all variations of the rate schedules available to that class;

(G) Staff means the staff of the Public Service Commission; and

(H) True-up year means the twelve (12)-month period beginning on the first day of the first calendar month following the effective date of the commission order approving an ECRM unless the effective date is on the first day of the calendar month. If the effective date of the commission order approving a rate mechanism is on the first day of a calendar month, then the true-up year begins on the effective date of the commission order. The first annual true-up period shall end on the last day of the twelfth calendar month following the effective date of the commission order establishing the ECRM. Subsequent true-up years shall be the succeeding twelve (12)-month periods. If a general rate proceeding is concluded prior to the conclusion of a true-up year, the true-up year may be less than twelve (12) months. If the commission approves both a fuel adjustment clause mechanism and an ECRM for the electric utility, the true-up year will be the same for both.

(2) Applications to Establish, Continue, or Modify an ECRM. Pursuant to the provisions of this rule, 4 CSR 240-2.060, and section 386.266, RSMo, only an electric utility in a general rate proceeding may file an application with the commission to establish, continue, or modify an ECRM by filing tariff schedules. Any party in a general rate proceeding in which an ECRM is in effect or proposed may seek to continue, modify, or oppose the ECRM. The commission shall approve, modify, or reject such applications to establish an ECRM only after providing the opportunity for a full hearing in a general rate proceeding. The commission shall consider all relevant factors that may affect the costs or overall rates and charges of the petitioning electric utility.

(A) The commission may approve the establishment, continuation or modification of an ECRM and rate schedules implementing an ECRM provided that it finds that the ECRM it approves is reasonably designed to provide the electric utility with a sufficient opportunity to earn a fair return on equity.

(B) The commission may take into account any change in business risk to the utility resulting from establishment, continuation or modification of the ECRM in setting the electric utility's allowed return in any rate proceeding, in addition to any other changes in business risk experienced by the electric utility.

(C) In determining which environmental cost components to include in an ECRM, the commission will consider, but is not limited to only considering, the magnitude of the costs, the ability of the utility to manage the costs, the incentive provided to the utility as a result of the inclusion or exclusion of the cost, and the extent to which the cost is related to environmental compliance.

(D) The commission may, in its discretion, determine what portion of prudently incurred environmental costs may be recovered in an ECRM and what portion shall be recovered in base rates.

(E) Any party to the general rate proceeding may oppose the establishment, continuation or modification of an ECRM and/or may propose alternative ECRMs for the commission's consideration including but not limited to modifications to the electric utility's proposed ECRM.

(F) The ECRM shall be based on known and measurable environmental costs that have been incurred by the electric utility.

(G) If an ECRM is approved, the commission shall determine the base environmental revenue requirement.

(H) If costs are requested to be recovered through the ECRM and the revenue to be collected in the ECRM rate schedules exceeds two and one-half percent (2.5%) of the electric utility's Missouri annual gross jurisdictional revenues, the electric utility cannot subsequently request that any cost identified as an environmental cost be recovered through a fuel rate adjustment mechanism.

(I) The electric utility shall include in its initial notice to customers regarding the general rate case, a commission approved description of how the costs passed through the proposed ECRM requested shall be applied to monthly bills.

(J) The electric utility shall meet the filing requirements in 4 CSR 240-3.162(2) in conjunction with an application to establish an ECRM and 4 CSR 240-3.162(3) in conjunction with an application to continue or modify an ECRM.

(3) Application for Discontinuation of an ECRM. The commission shall allow or require the rate schedules that define and implement an ECRM to be discontinued and withdrawn only after providing the opportunity for a full hearing in a general rate proceeding. The commission shall consider all relevant factors that affect the cost or overall rates and charges of the petitioning electric utility.

(A) Any party to the general rate proceeding may oppose the discontinuation of an ECRM on the grounds that the electric utility is currently, or in the next four (4) years, is likely to experience declining costs. If the commission finds that the electric utility is seeking to discontinue the

ECRM under these circumstances, the commission shall not permit the ECRM to be discontinued, and shall order its continuation or modification. To continue or modify the ECRM under such circumstances, the commission must find that it provides the electric utility with a sufficient opportunity to earn a fair rate of return on equity.

(B) The commission may take into account any change in business risk to the corporation resulting from discontinuance of the ECRM in setting the electric utility's allowed return in any rate proceeding, in addition to any other changes in business risk experienced by the electric utility.

(C) The electric utility shall include in its initial notice to customers regarding the general rate case, a commission approved description of why it believes the ECRM should be discontinued.

(D) Subsections (2)(C) through (H) shall apply to any proposal for continuation or modification.

(E) The electric utility shall meet the filing requirements in 4 CSR 240-3.162(4).

(4) Periodic adjustments of ECRMs If an electric utility files proposed rate schedules to adjust its ECRM rates between general rate proceedings, the staff shall examine and analyze the information filed by the electric utility in accordance with 4 CSR 240-3.162 and additional information obtained through discovery, if any, to determine if the proposed adjustment to the ECRM is in accordance with the provisions of this rule, section 386.266, RSMo, and the ECRM established in the most recent general rate proceeding. The staff shall submit a recommendation regarding its examination and analysis to the commission not later than thirty (30) days after the electric utility files its tariff schedules to adjust its ECRM rates. If the ECRM rate adjustment is in accordance with the provisions of this rule, section 386.266, RSMo, and the ECRM established in the most recent general rate proceeding, the commission shall either issue an interim rate adjustment order approving the tariff schedules and the ECRM rate adjustments within sixty (60) days of the electric utility's filing or, if no such order is issued, the tariff schedules and the ECRM rate adjustments shall take effect sixty (60) days after the tariff schedules were filed. If the ECRM rate adjustment is not in accordance with the provisions of this rule, section 386.266, RSMo, or the ECRM established in the most recent rate proceeding, the commission shall reject the proposed rate schedules within sixty (60) days of the electric utility's filing and may instead order implementation of an appropriate interim rate schedule(s).

(A) The periodic adjustments shall be limited to the expense items and the capital projects that are used to determine the environmental revenue requirement in the previous general rate proceeding and those investments or expenses necessary to comply with the electric utility's Environmental Compliance Plan for the period the ECRM is in effect.

1. The costs for capital projects will be eligible for recovery via a periodic adjustment so long as the capital cost of the item when it is placed into service is greater than or equal to the original cost (as of the time that such least costly capital item was placed into service) of the least costly capital item that was included in the environmental revenue requirement (to be determined as provided in 4 CSR 240-20.091(1)(D)); and

2. Waivers from the limitations in this subsection (4)(A) may be sought for capital projects placed into service that could not have been anticipated in the previous general rate proceeding or that do not meet the threshold provided for in the immediately preceding sentence;

(B) The periodic adjustment shall reflect a comprehensive measurement of both increases and decreases to the environmental revenue requirement established in the prior general rate proceeding plus the additional environmental costs incurred since the prior rate proceeding.

(C) Any periodic adjustment made to ECRM rate schedules shall not generate an annual amount of general revenue that exceeds two and one-half percent (2.5%) of the electric utility's Missouri gross jurisdictional revenues established in the electric utility's most recent general rate proceeding.

1. Missouri gross jurisdictional revenues shall be the amount established in the electric utility's most recent general rate proceeding and exclude gross receipts tax, sales tax

and other similar pass-through taxes not included in tariffed rates for regulated services;

2. The electric utility shall be permitted to collect any applicable gross receipts tax, sales tax, or other similar pass-through taxes and such taxes shall not be counted against the two and one-half percent (2.5%) rate adjustment cap; and
3. Any environmental costs, to the extent addressed by the ECRM, not recovered as a result of the two and one-half percent (2.5%) limitation on rate adjustments may be deferred, at a carrying cost each month equal to the utility's net of tax cost of capital, for recovery in a subsequent year or in the utility's next general rate proceeding.

(D) An electric utility with an ECRM shall file one (1) mandatory adjustment to its ECRM in each true-up year coinciding with the true-up of its ECRM. It may also file one (1) additional adjustment to is ECRM within a true-up year with the timing and number of such additional filings to be determined in the general rate proceeding establishing the ECRM and in general rate proceedings thereafter.

(E) The electric utility must be current on its submission of its Surveillance Monitoring Reports as required in section (9) and its monthly reporting requirements as required by 4 CSR 240-3.162(5) in order for the commission to process the electric utility's requested ECRM adjustment increasing rates.

(F) If the staff, Office of the Public Counsel (OPC) or other party who receives the information that the electric utility is required to submit in 4 CSR 240-3.162 and as ordered by the commission in a previous proceeding, believes that the information required to be submitted pursuant to 4 CSR 240-3.162 and the commission order establishing the ECRM has not been submitted in compliance with that rule, it shall notify the electric utility within ten (10) days of the electric utility's filing of an application or tariff schedules to adjust the ECRM rates and identify the information required. The electric utility shall supply the information identified by the party, or shall notify the party that it believes the information provided was in compliance with the requirements of 4 CSR 240-3.162, within ten (10) days of the request. If the electric utility does not timely supply the information, the party asserting the failure to provide the required information must timely file a motion to compel with the commission. While the commission is considering the motion to compel, the proceeding time line for the adjustment to increase ECRM rates shall be suspended. If the commission then issues an order requiring the information to be provided, the time necessary for the information to be provided shall further extend the processing time line for the adjustment to increase ECRM rates. For good cause shown the commission may further suspend this time line. Any delay in providing sufficient information in compliance with 4 CSR 240-3.162 in a request to decrease ECRM rates shall not alter the processing time line.

(5) True-up of an ECRM. An electric utility that files for an ECRM shall include in its tariff schedules and application, if filed in addition to tariff schedules, provision for true-ups on at least an annual basis which shall accurately and appropriately remedy any over-collection or under-collection through subsequent rate adjustments or refunds.

(A) The subsequent true-up rate adjustments or refunds shall include interest at the electric utility's short-term borrowing rate. The interest rate on accumulated ECRM under-collections or over-collections shall be calculated on a monthly basis for each month the ECRM rate is in effect, equal to the weighted average interest rate paid by the electric utility on short-term debt for that calendar month. This rate shall then be applied to a simple average of the same month's beginning and ending cumulative ECRM over-collection or under-collection balance. Each month's accumulated interest shall be included in the ECRM over-collection or under-collection balances on an ongoing basis.

(B) The true-up adjustment shall be the difference between the revenue collected and the revenue authorized for collection during the true-up period and billed revenues associated with the ECRM during the true-up period.

(C) The electric utility must be current on its submission of its Surveillance Monitoring Reports as required in section (9) and its monthly reporting requirements as required by 4 CSR 240-

3.162(5) at the time that it files its application for a true-up of its ECRM in order for the commission to process the electric utility's requested annual true-up of any under-collection.

(D) The staff shall examine and analyze the information filed by the electric utility pursuant to 4 CSR 240-3.162 and additional information obtained through discovery, to determine whether the true up is in accordance with the provisions of this rule, section 386.266 RSMo and the ECRM established in the electric utility's most recent general rate proceeding. The staff shall submit a recommendation regarding its examination and analysis to the commission not later than thirty (30) days after the electric utility files its tariff schedules for a true-up. The commission shall either issue an order deciding the true-up within sixty (60) day of the electric utility's filing, suspend the time line of the true-up in order to receive additional evidence and hold a hearing if needed or, if no such order is issued, the tariff schedules and the ECRM rate adjustments shall take effect by operation of law sixty (60) days after the electric utility's filing.

1. If the staff, OPC or other party who receives the information that the electric utility is required to submit in 4 CSR 240-3.162 and as ordered by the commission in a previous proceeding, believes the information that is required to be submitted pursuant to 4 CSR 240-3.162 and the commission order establishing the ECRM has not been submitted or is insufficient to make a recommendation regarding the electric utility's true-up filing, it shall notify the electric utility within ten (10) days of the electric utility's filing and identify the information required. The electric utility shall supply the information identified by the party, or shall notify the party that it believes the information provided was responsive to the requirements, within ten (10) days of the request. If the electric utility does not timely supply the information, the party asserting the failure to provide the required information must timely file a motion with the commission. While the commission is considering the motion to compel the processing time line for the adjustment to the ECRM rates shall be suspended. If the commission then issues an order requiring the information to be provided, the time necessary for the information to be provided shall further extend the processing time line. For good cause shown the commission may further suspend this time line.
2. If the party requesting the information can demonstrate to the commission that the adjustment shall result in a reduction in the ECRM rates, the processing time line shall continue with the best information available. When the electric utility provides the necessary information, the ECRM shall be adjusted again, if necessary, to reflect the additional information provided by the electronic utility.

(6) Duration of ECRMs and Requirement for General Rate Case. Once an ECRM is approved by the commission, it shall remain in effect for a term of not more than four (4) years unless the commission earlier authorizes the modification, extension, or discontinuance of the ECRM in a general rate proceeding, although an electric utility may submit proposed rate schedules to implement periodic adjustments to its ECRM rates between general rate proceedings.

(A) If the commission approves an ECRM for an electric utility, the electric utility must file a general rate case with the effective date of new rates to be no later than four (4) years after the effective date of the commission order implementing the ECRM, assuming the maximum statutory suspension of the rates so filed.

(B) The four (4)-year period shall not include any periods in which the electric utility is prohibited from collecting any charges under the adjustment mechanism, or any period for which charges collected under the ECRM must be fully refunded. In the event a court determines that the ECRM is unlawful and all moneys collected are fully refunded as a result of such a decision, the electric utility shall be relieved of any obligation to file a rate case. The term fully refunded as used in this section does not include amounts refunded as a result of reductions in net environmental compliance costs or prudence adjustments.

(7) Prudence Reviews Respecting an ECRM. A prudence review of the costs subject to the ECRM shall be conducted no less frequently than at eighteen (18)-month intervals.

(A) All amounts ordered refunded by the commission shall include interest at the electric utility's short-term borrowing rate. The interest shall be calculated on a monthly basis in the same manner as described in subsection (5)(A).

(B) The staff shall submit a recommendation regarding its examination and analysis to the commission not later than one hundred eighty (180) days after the staff initiates its prudence audit. The timing and frequency of prudence audits for each ECRM shall be established in the general rate proceeding in which the ECRM is established. The staff shall file notice within ten (10) days of starting its prudence audit. The commission shall issue an order not later than two hundred ten (210) days after the staff commences its prudence audit if no party to the proceeding in which the prudence audit is occurring files, within one hundred ninety (190) days of the staff's commencement of its prudence audit, a request for a hearing.

1. If the staff, OPC or other party auditing the ECRM believes that insufficient information has been supplied to make a recommendation regarding the prudence of the electric utility's ECRM, it may utilize discovery to obtain the information it seeks. If the electric utility does not timely supply the information, the party asserting the failure to provide the required information must timely file a motion to compel with the commission. While the commission is considering the motion to compel the processing time line shall be suspended. If the commission then issues an order requiring the information to be provided, the time necessary for the information to be provided shall further extend the processing time line. For good cause shown the commission may further suspend this time line.

2. If the time line is extended due to an electric utility's failure to timely provide sufficient responses to discovery and a refund is due to the customers, the electric utility shall refund all imprudently incurred costs plus interest at the electric utility's short-term borrowing rate. The interest shall be calculated on a monthly basis in the same manner as described in subsection (5)(A).

(8) Disclosure on Customers' Bills. Any amounts charged under an ECRM approved by the commission shall be separately disclosed on each customer's bill. Proposed language regarding this disclosure shall be submitted to the commission for the commission's approval.

(9) Submission of Surveillance Monitoring Reports. Each electric utility with an approved ECRM shall submit to staff, OPC and parties approved by the commission a Surveillance Monitoring report in the form and having the content provided for by 4 CSR 240-3.162(6).

(A) The Surveillance Monitoring Report shall be submitted within fifteen (15) days of the electric utility's next scheduled United States Securities and Exchange Commission (SEC) 10-Q or 10-K filing with the initial submission within fifteen (15) days of the electric utility's next scheduled SEC 10-Q or 10-K filing following the effective date of the commission order establishing the ECRM.

(B) If the electric utility also has an approved fuel rate adjustment mechanism, the electric utility must submit a single Surveillance Monitoring Report for both the ECRM and the fuel rate adjustment mechanism. However, for the Surveillance Monitoring Report to be complete for the ECRM, it must include a list of all settlements in regards to environmental compliance causing the electric utility to incur expenses or make investments in excess of one hundred thousand dollars ($100,000) or fines against the electric utility in regards to environmental compliance greater than one hundred thousand dollars ($100,000) as required in 4 CSR 240-3.162(6)(A)5.G.

(C) Upon a finding that a utility has knowingly or recklessly provided materially false or inaccurate information to the commission regarding the surveillance data prescribed in 4 CSR 240-3.162(6), after notice and an opportunity for a hearing, the commission may suspend an ECRM or order other appropriate remedies as provided by law.

(10) Pre-Existing Adjustment Mechanisms, Tariffs and Regulatory Plans. The provisions of this rule shall not affect:

(A) Any adjustment mechanism, rate schedule, tariff, incentive plan, or other ratemaking mechanism that was approved by the commission and in effect prior to the effective date of this rule; and

(B) Any experimental regulatory plan that was approved by the commission and in effect prior to the effective date of this rule.

(11) Nothing in this rule shall preclude a complaint case from being filed, as provided by law, on the grounds that a utility is earning more than a fair return on equity, nor shall an electric utility be permitted to use the existence of its ECRM as a defense to a complaint case based upon an allegation that it is earning more than a fair return on equity. If a complaint is filed on the grounds that a utility is earning more than a fair return on equity, the commission shall issue a procedural schedule that includes a clear delineation of the case time line no later than sixty (60) days from the date the complaint is filed.

(12) Rule Review. The commission shall review the effectiveness of this rule by no later than December 31, 2011, and may, if it deems necessary, initiate rulemaking proceedings to revise this rule.

(13) Waiver of Provisions of this Rule. Provisions of this rule may be waived by the commission for good cause shown after an opportunity for a hearing.

AUTHORITY: sections 386.250 and 393.140, RSMo 2000 and section 386.266, RSMo *Supp. 2007*. Original rule filed Oct.* 31, *2007, effective June 30, 2008.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; 386.266, RSMo 2005; and 393.140, RSMo 1939, amended 1949, 1967.*

FILED
February 7, 2008
Data Center
Missouri Public
Service Commission

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Proposed Rules 4 CSR 240-3.162 and 4 CSR 240-20.091, Environmental Cost Recovery Mechanisms.	))))	Case No. EX-2008-0105

PREPARED REMARKS OF AMERENUE WITNESS MARK C. BIRK ECRM RULEMAKING HEARING, JANUARY 17, 2008

I. Introduction

My name is Mark C. Birk, and I am the Vice President of Power Operations for AmerenUE. In that capacity I am responsible for all of AmerenUE's generating plants, other than the Callaway Nuclear Plant.

As explained in the comments previously filed by AmerenUE, we are generally supportive of the proposed rules submitted by the Staff and published by the Commission in this proceeding. The proposed rules reflect the relevant policy decisions made by the Commission in the recent fuel adjustment clause (FAC) rulemaking proceeding, and they generally create a workable environmental cost recovery mechanism (ECRM) which will be critical for electric utilities facing huge, federally mandated environmental costs over the next several years and beyond. The proposed rules also contain numerous consumer protections as required by Senate Bill 179 and as reflected in the FAC rules. We believe this structure fairly balances the need of utilities to promptly recover unavoidable environmental costs, with the protections consumers need to insure that these costs are prudent.

The one aspect of the proposed rules that we disagree with is the requirement that electric utilities must separate all of their existing rate base into "environmental" and "non-environmental" categories, and include any and all changes to existing "environmental" rate base in the ECRM. As explained in detail in our previously filed comments, we believe that this

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AmerenUE Exhibit No. 3
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requirement would create an extremely complicated, contentious and unworkable process where parties would be free to debate the "environmental" qualities of every pipe, drain, smokestack, wall, floor, control panel, etc. at every plant. Electric poles and wires as well as transformer cases arguably provide some environmental benefit, and one could expect the opponents of the ECRM to take every opportunity to make such arguments, and mire any Commission proceeding addressing an ECRM for a particular utility in this bog. The bottom line is that the requirement that each piece of rate base must be so classified would effectively make the ECRM unusable, and therefore should be rejected.

The proposed treatment of existing rate base items contained in the prefiled comments of MEDA, and endorsed by AmerenUE, handles capital infrastructure investment under the ECRM in the same way that the Commission determined it should be handled for natural gas and water in the analogous Infrastructure System Replacement Surcharge regulations. This approach is fair to both utilities and consumers, and provides consistency in the treatment of rate base for purposes of a surcharge.

II. Comments of Other Parties

Several other parties, who have consistently opposed rate adjustment mechanisms before the Legislature, in rulemaking proceedings before this Commission, and/or in rate case proceedings, have filed comments that simply rehash arguments that the Commission has previously rejected, or that are designed to prevent utilities from adopting a workable ECRM. My remarks concerning some of these comments are provided below:

Office of the Public Counsel (OPC) Comments:

4 CSR 240-20.091(1)(B) and (4)(C): OPC proposes to change the language of Senate Bill 179 that enables the Commission to adopt an ECRM for an electric utility "to reflect increases and decreases in its prudently incurred costs . . ." to one that reflects "*some or all of*

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the net increases or decreases in its prudently incurred costs." If the General Assembly intended to say "some or all" it would have done so in the statute. The criteria the General Assembly established for the costs that could be included in the ECRM are twofold. First, the costs must be prudent. Second, the costs must be incurred in order to comply with an environmental law, regulation or rule. The Commission should not add a third criterion; that is, establish an arbitrary limit on inclusion of increases or decreases in costs that meet the criteria provided by the General Assembly. In fact, counsel advises that adoption of OPC's proposal in this regard may be unlawful.

4 CSR 240-20.091(2)(A) and 4 CSR 240-3.162(2)(E), (4)(C): OPC advocates further amendments to the language contained in the statute by adding the words "necessary and" and "but no greater than a fair return on equity" and other similar language in these sections of the proposed rule. The statutory language does not impose a cap (or floor) on what a utility may actually earn in the up to four years between rate cases that could occur given the rate case requirements in the statute. The General Assembly quite explicitly determined that the Commission needed to find only that a proposed ECRM is "reasonably designed" to provide the utility a sufficient opportunity to earn a fair return on equity, but did not require the Commission to find that an ECRM is absolutely necessary to create that opportunity. Nor did the General Assembly give utilities assurance that an ECRM will guarantee that the utility will earn a fair return. The point is that the Commission needs to find that upon establishment, it is reasonable to expect that with the ECRM in place the utility will have a sufficient opportunity to earn a fair return on equity (ROE), with the recognition that the actual ROE may be above or below that amount. Consistent with other changes OPC proposes, OPC proposes a ceiling on earnings that is not in the statute, but proposes no floor. Neither a floor nor a ceiling is appropriate given the language of the statute.

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4 CSR 240-20.091(2)(C): OPC attempts to create yet another non-statutory standard by injecting an examination of "volatility" of costs into the question of whether to approve an ECRM. I believe the context surrounding the adoption of Senate Bill 179 makes clear that the ECRM provisions of the statute were made available as a tool for the Commission's use to address the prospect of huge expenditures to control pollution facing the utility industry. Coupled with the focus on ensuring that the utility has a sufficient opportunity to earn a fair return on equity, it seems clear that the General Assembly was not concerned with whether the cost profile resembled a zig-zagging line, but rather, was concerned with allowing timely cost recovery of these enormous mandated environmental costs. Installation of a $500 million scrubber every couple of years may not be "volatile" in the sense intended by OPC, but it will certainly inject volatility into utility earnings based on an item mandated by law and beyond the utility's control.

4 CSR 240-20.091(2)(F): OPC's next proposed change attempts to limit environmental costs that may be included in the ECRM to "known and measurable" costs. This is an unnecessary addition, since all environmental costs must already be incurred to be included. The addition of this language is at best redundant, and at worst confuses the standard for including environmental costs under the rules.

4 CSR 240-20.091(3)(B): Changing the word "may" to "shall" is another attempt to change the statute itself, which reads the Commission "may take into account any change in business risk ...." Again, counsel advises that the Commission cannot simply amend the General Assembly's statute, which is a point that seems obvious.

4 CSR 240-20.091(4)(C)4: This change is OPC's first attempt to inject an "earnings test" into the ECRM rules. It is my understanding that the Commission already found, in the rulemaking for the FAC, that the statute does not contemplate an earnings test, as evidenced by

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the following statement in the Commission's Order of Rulemaking for Chapter 20 of the FAC rules: "The Commission finds that an earnings threshold for eligibility to use a RAM is contrary to the intent of the legislature, as articulated in SB 179. Therefore, no such eligibility criteria will be included in the rule." Moreover, the Commission already found that the appropriate mechanism, if others believe that a utility is over-earning, is to use the complaint mechanisms which were included in the FAC rule, and which also appear in this proposed rule at 4 CSR 240-20.091(12). An earnings test would turn every adjustment of the ECRM into a full-blown rate case, and contravene the intent of the Legislature in enacting Senate Bill 179. The Commission properly rejected the idea of an earnings test in developing FAC rules, and it should also reject that concept here.

4 CSR 240-20.091(4)(C)5- 8: These changes all amount to a direct attack on the cap on *annual* increases that are allowed under an ECRM, and an effort to defer cost recovery far beyond the period contemplated by Senate Bill 179. The statutory language could hardly be clearer:

> Any rate adjustment made under such rate schedules shall not exceed an annual amount equal to two and one-half percent . . . * * * Any costs not recovered as a result of the annual two and one-half percent limitation on rate adjustments may be deferred, at a carrying cost each month equal to the utilities net of tax cost of capital, for recovery in a subsequent year or in the corporation's next general rate case or complaint proceeding.

An ECRM only has a "life" of up to four years. Every four years, the earlier ECRM ends, and if an ECRM is to exist, a new ECRM must be approved. OPC's suggestion would apparently allow huge deferrals, with interest, to build up not just in the year following the year in which the *annual* cap may have operated, but years and years into the future, and indeed, beyond the "life" of the ECRM under which the deferral was created. The presence of a two and one-half percent cap in the ECRM provisions (without a cap in the fuel adjustment clause provisions of the statute) reflects that the General Assembly understood that these ECRM

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investments could be huge, and that some annual cap might be needed. But the General Assembly balanced that need with the recognition that the deferrals would bear interest and needed to be recovered no later than the next rate case, which would end, at most, four years after the ECRM was established.

It is also my understanding that if proposals such as that advocated by OPC were adopted, the support to credit quality provided by the ECRM will be significantly eroded if not eliminated because credit rating agencies will view the cash flows the ECRM was supposed to timely provide as too small or too speculative to support credit quality. This, in turn, may raise borrowing costs at the very time when the utility's borrowing needs are greatest. This, ultimately, creates more ratepayer expense in the form of higher borrowing costs.

4 CSR 240-20.091(11): With this addition, the OPC proposes to permit parties to propose incentive mechanisms or performance-based programs as part of an ECRM. The same provision appears in Chapter 20 of the FAC rules, but as Staff points out in its Comments filed in this rulemaking, it is not authorized for an ECRM due to the clear difference between the statutory language in subsection 1 of Section 386.266 (dealing with FACs) and the statutory language in subsection 2 (dealing with ECRMs). Subsection 1 gives the Commission authority to "include . . . incentives to improve the efficiency and cost-effectiveness of its fuel and purchased power procurement activities." Subsection 2 contains no such authority. Consequently, subsection (11) of the proposed rule is not authorized by statute and cannot be included in the ECRM rules.

4 CSR 240-3.162(2)(P) & (Q) and (3)(P): With this change, OPC proposes to require five years of extensive historic "rate case" type data and forecasts of such data four years into the future. Participants in the roughly 15 roundtables which led to the initial proposal of FAC rules also proposed similar provisions for inclusion in the FAC rules, which were rejected. 4 CSR

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240-3.162(2)(O) requires electric utilities seeking an ECRM to authorize the Staff to release five years of surveillance reports to all parties to the case. This was deemed adequate by the Commission for the FAC regulations and it is adequate for these regulations as well. Staff, which historically performs the most regular and complete audit of rate adjustment filings, did not agree to include these provisions and the Commission did not include them in the FAC rules. As a consequence, they should not be included in these ECRM rules.

AARP Comments:

AARP echoes OPC's advocacy of an "earnings test" and of provisions in the rules that would create huge deferrals that are inconsistent with the statute. Insofar as I have already addressed both issues earlier, I won't repeat them here.

AARP does advance some additional arguments regarding the earnings test issue. First, AARP argues that the proposed rules "place no check" on the possibility that a utility would overearn. As I previously noted, the Commission has already rejected this argument, and found that the existing protections against overearning do not require the adoption of an earnings test for each and every filing. The statute was specifically designed to limit the operation of the ECRM to a period of just four years. If an earnings test were intended, a rate case on the front end and on the back end would simply not have been required. In addition, if an overearnings complaint is filed, the rules require that a procedural schedule must be set within 60 days (4 CSR 240-20.091(12)), a framework that hardly can be described as placing no check on the earnings of utilities.

AARP also proposes an additional change to limit the "environmental costs" that could be recovered under the ECRM to only costs incurred because of a law or regulation that takes effect *after* the ECRM is established in the rate case. If AARP's proposal were adopted, none of the enormous costs utilities will soon incur under the Clean Air Act Amendments of 2005,

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including the resulting Clean Air Mercury Rule and Clean Air Interstate Rule, could be recovered under the ECRM. No costs incurred after the rate case is over, but before the next rate case to occur 37 months later, could be recovered if those costs arose under the Clean Air Act of 1970, the Clean Air Act Amendments of 1990, or under the host of environmental laws and regulations adopted over the past four decades. In my opinion, to believe that the General Assembly enacted this mechanism, with an every-four-year rate case requirement, and with an annual cap on rate increases, but intended for the Commission to ignore these significant costs is ludicrous.

AARP's arguments also fail to withstand scrutiny. AARP argues that "surely, the intent of the law was not to permit recovery for costs that could have been taken into account during the rate case." Exactly how AARP believes that a future environmental cost could be "taken into account during the rate case" when rates in Missouri are set based upon an historic test year is unknown.

If the Commission adopts AARP's proposal, it might as well adopt no ECRM rules at all. This is because the ECRM will be useless to utilities. Credit quality will not be supported, and borrowing costs will very likely simply increase dramatically given the huge borrowing needs utilities will face to make mandated environmental investments in the coming years. Moreover, the ECRM will provide no incentive to more timely make these investments, an initiative I believe the General Assembly and this Commission would support.

Noranda:

Noranda has resurrected a proposal it made in the FAC rulemaking that was flatly rejected. Noranda suggests that the proposed rule (4 CSR 240-20.092(2)(D)) allows the Commission to not only decide that some portion of environmental costs should be recovered in

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base rates, with the rest to be recovered in the ECRM, but that the Commission can just arbitrarily deny recovery of a part of the costs entirely.

In rejecting this reading of the statutory language relied upon by Noranda, the Commission stated that it "must disagree with this comment in that it would not allow for the setting of just and reasonable rates that allow the utility a reasonable return." (Order of Rulemaking for the FAC Rules, p. 4).

MIEC:

MIEC's central comment also consists of its advocacy, as it did in the FAC rulemaking proceedings, for an earnings test. I (and the Commission) have already addressed why an earnings test is inappropriate.

I would note that MIEC misstates some important facts, however. MIEC argues that there is a "high likelihood" that utilities will overearn. Every electric utility in this state has obtained a Commission-approved rate increase in the very recent past. Relentlessly increasing fuel and material costs, as well as the huge environmental expenditures which would be the subject of this rule, are well-documented. (*See* the attached article from the September/October edition of *Electric Perspectives—An Upward Climb* by Marc Chupka and Gregory Basheda.) In this environment, the idea that it would be "highly likely" that a utility will overearn is simply untrue. This renders MIEC's reference to rate decreases, the last of which occurred nearly six years ago, irrelevant.

III. <u>A Workable Alternative to Include Changes to Existing Environmental Rate Base</u>

As previously discussed, AmerenUE does not believe that it is appropriate for changes in existing "environmental" rate base to be included in the ECRM. In AmerenUE's view, changes in existing environmental rate base should be addressed in a general rate proceeding, similar to changes in existing rate base that would qualify for ISRS treatment. However, if the

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Commission determines that such changes must be included in the ECRM, the changes should be limited to major components of rate base that clearly serve an environmental purpose. Parties should not be free to squabble over every pipe, drain, control panel, etc. AmerenUE believes that the rules would reflect this approach if the definition of "environmental revenue requirement" contained in the rules is modified as follows:

> The environmental revenue requirement shall be comprised of the following: (i) all environmental costs that are expensed, rather than capitalized, included in the electric utility's revenue requirement in the general rate proceeding in which the ECRM is established, plus (ii) the costs of any major capital items whose primary purpose is to permit the electric utility to comply with any federal, state or local environmental law, regulation or rule. Representative examples of such capital items to be included (as of January, 2008) are electrostatic precipitators, NOx emissions control equipment and flue gas desulfurization equipment. The costs of such capital items shall be those reflected on the electric utility's books and records as of the last day of the test year, as updated, utilized in the general rate proceeding in which the ECRM is established.

If this approach is adopted, there may have to be some additional conforming changes to the proposed rules. In addition, if this change is adopted, AmerenUE recommends that electric utilities be permitted up to three (3) ECRM adjustments each year. This would make sense since the change would be a departure from the ISRS approach to addressing rate base, and it would be consistent with the FAC rules, which permit up to three adjustments per year.

If there must be a departure from the ISRS method, this definition of "environmental revenue requirement" will prevent the rule from being completely unworkable.

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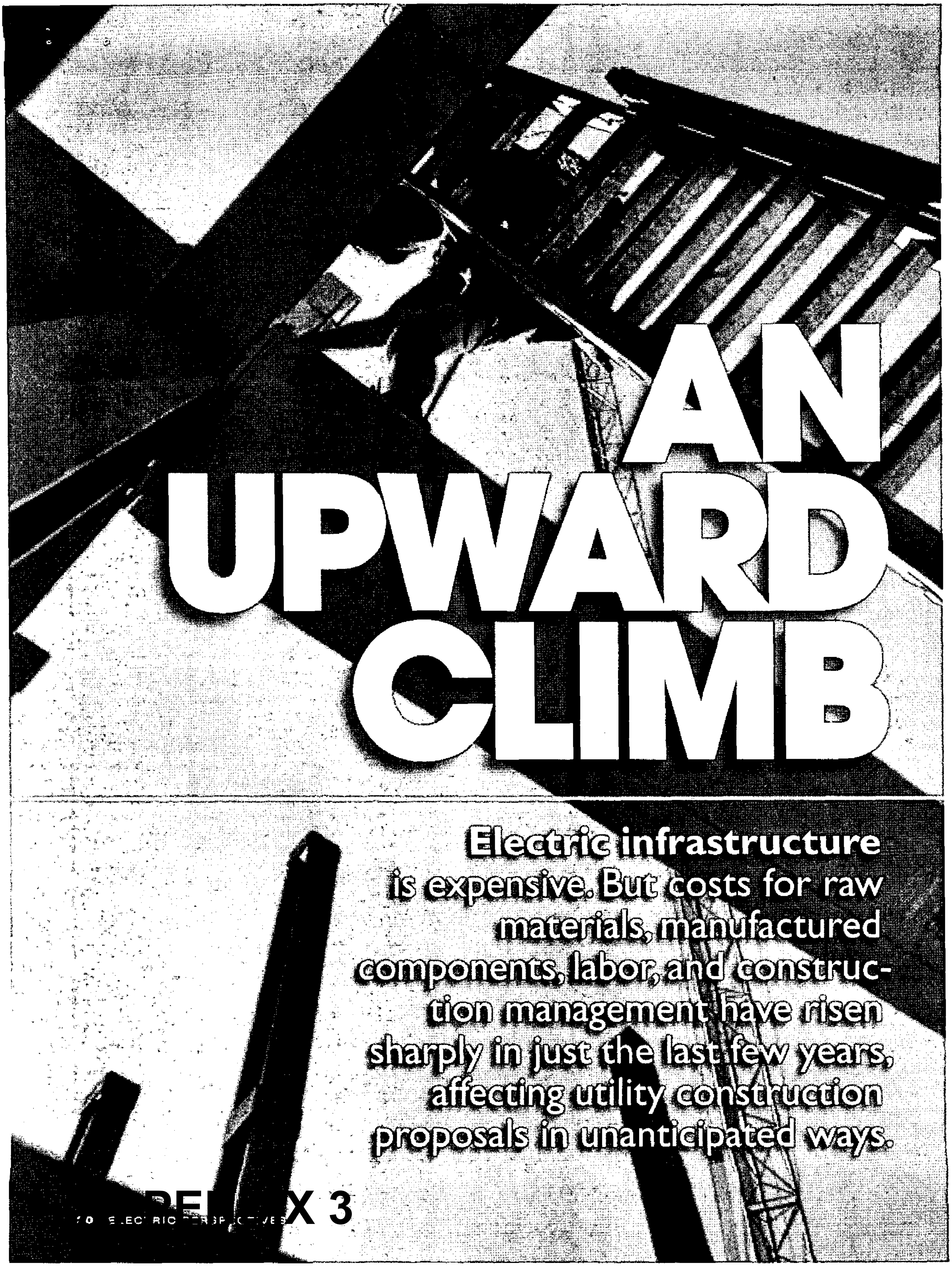

AN UPWARD CLIMB

Electric infrastructure is expensive. But costs for raw materials, manufactured components, labor, and construction management have risen sharply in just the last few years, affecting utility construction proposals in unanticipated ways.

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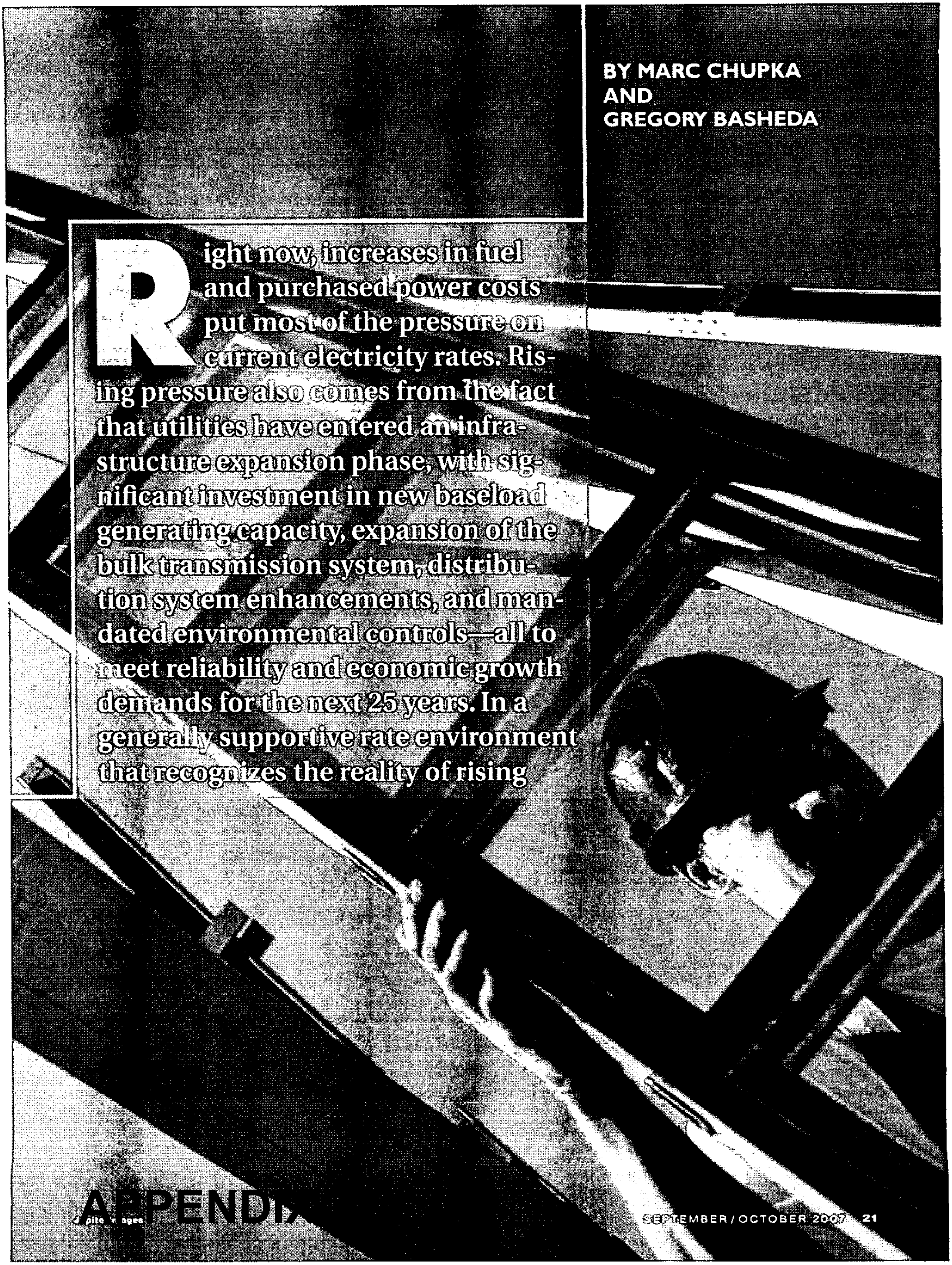
BY MARC CHUPKA
AND
GREGORY BASHEDA



Right now, increases in fuel and purchased power costs put most of the pressure on current electricity rates. Rising pressure also comes from the fact that utilities have entered an infrastructure expansion phase, with significant investment in new baseload generating capacity, expansion of the bulk transmission system, distribution system enhancements, and mandated environmental controls—all to meet reliability and economic growth demands for the next 25 years. In a generally supportive rate environment that recognizes the reality of rising

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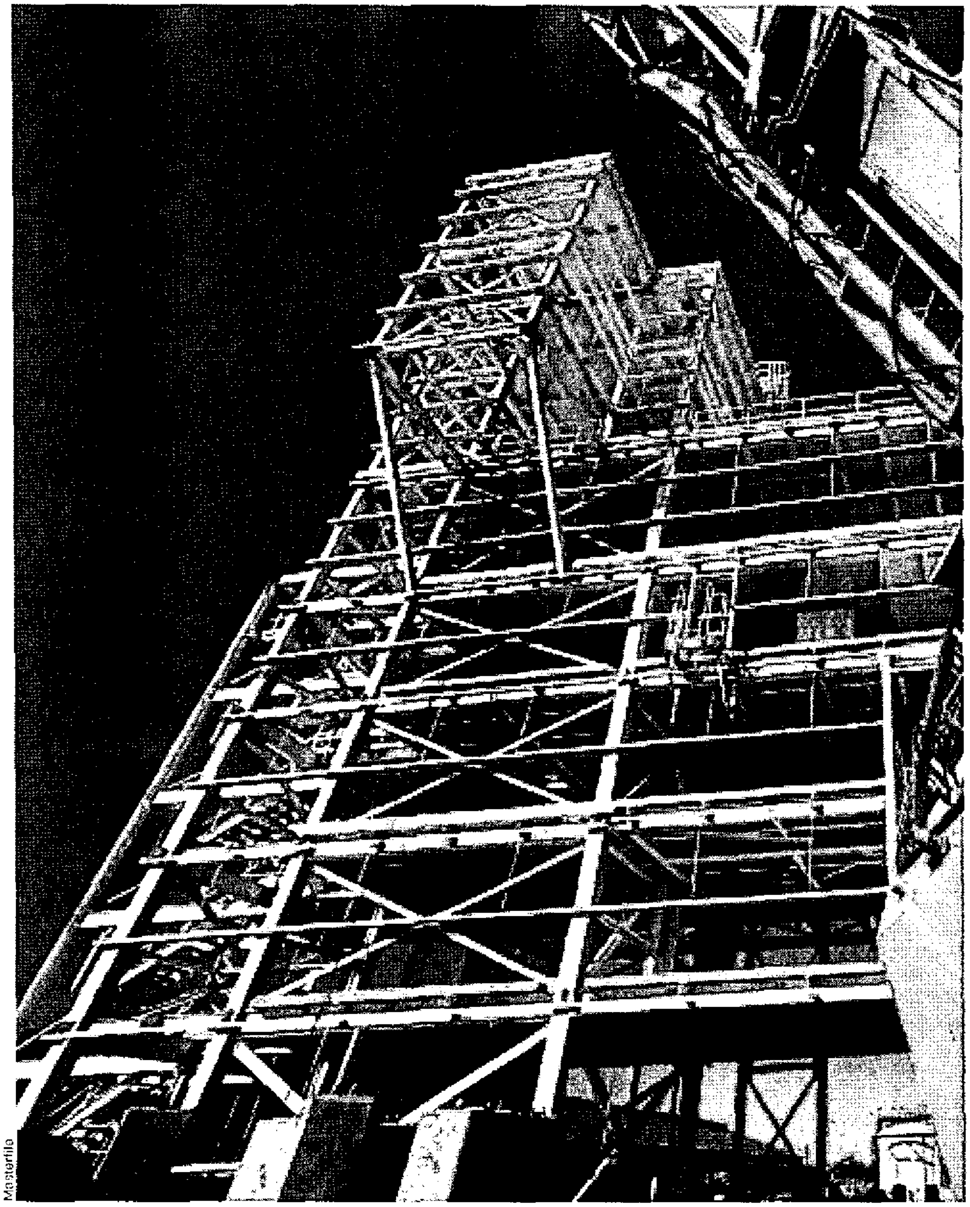
Jupiter Images

Recent rise. Steel prices have increased about 60 percent since 2003. Prices for gas turbines shot up 17 percent in 2006 alone. Generation projects already in the works—mostly combined-cycle gas and wind power—feel the pinch, but the real squeeze is on proposed projects.



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prices, the industry could probably make the infrastructure investments cost-effectively.

That's essentially what we concluded in a June 2006 Edison Foundation report, "Why Are Electricity Prices Rising?" [See also "Behind the Rise in Prices" in the July/August 2006 *Electric Perspectives.*]

The cost pressures from elevated fuel and purchased power prices will continue, and the infrastructure needs remain. But pressures on the long-run price of electric power have another dimension: Namely, substantial increases in the construction costs for utility infrastructure projects. Some of the factors underlying these cost trends are straightforward. Dramatic spikes in the prices for raw materials—such as steel and cement—have increased construction costs directly, for example. Some factors are less transparent, like the effect those commodity prices have on the cost of manufactured components. In most cases, the driving forces behind such cost increases have been high global demand for commodities and manufactured goods, higher production and transportation costs (in part owing to elevated fuel prices), and a weakening U.S. dollar.

This article is based on "Rising Utility Construction Costs: Sources and Impacts," a white paper published under the auspices of the Edison Foundation in Washington, DC. The Foundation is a nonprofit organization founded to provide knowledge, insight, and leadership to the goal of bringing the benefits of electricity to families, businesses, and industries worldwide. To view an electronic copy of the full paper, visit www.eei.org.

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Labor costs are a smaller contributor to the general rise, but that contribution may grow as new, large construction projects boost the demand for increasingly scarce specialized and skilled workers. There also is a growing backlog of project contracts at large engineering, procurement, and construction (EPC) firms—the utility industry's construction contractors—and bids for construction management have begun to rise as a result. Although it is not possible to quantify the impact on future proposals by EPC firms, it is reasonable to assume that bids will become less cost-competitive as new projects go into the queue. (And investments by power companies around the world will total about $11 trillion dollars by 2030, according to "World Energy Investment Outlook 2006.")

The jumps in material, equipment, labor, and management costs for utility construction have affected all electric-sector investment. In the generation area, all technologies have seen cost increases in the past three years, from coal plants to wind projects. Large proposed transmission projects have undergone cost revisions. Distribution system equipment costs have risen rapidly. Indeed, between January 2004 and January 2007, the costs of steam-generation plants, transmission projects, and distribution equipment rose by 25-35 percent. The cost of gas turbines, fairly steady in the early part of the decade, increased by 17 percent during 2006 alone. Compare this to the 8-percent general price increase during the three-year period.

The rapid increases in utility construction costs have raised the price of recently completed projects (mostly gas-fired and wind-powered projects), though in many of those cases the

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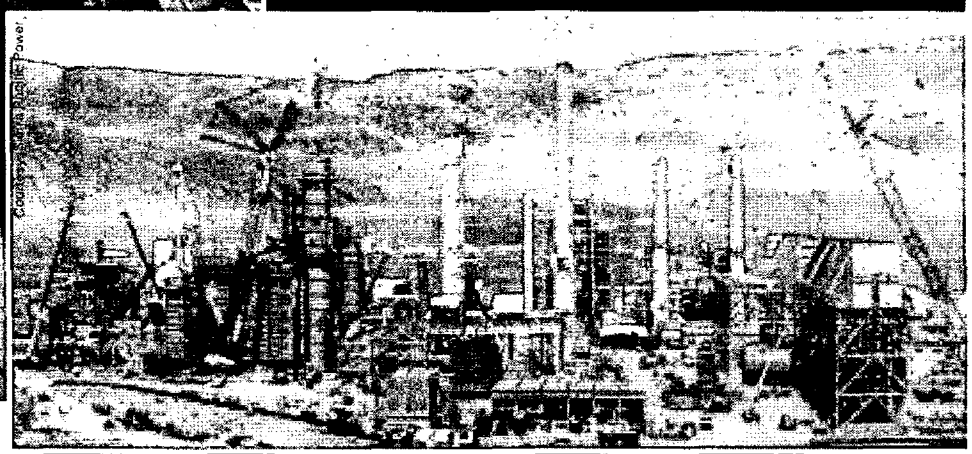
Generation:

What Are We Building?

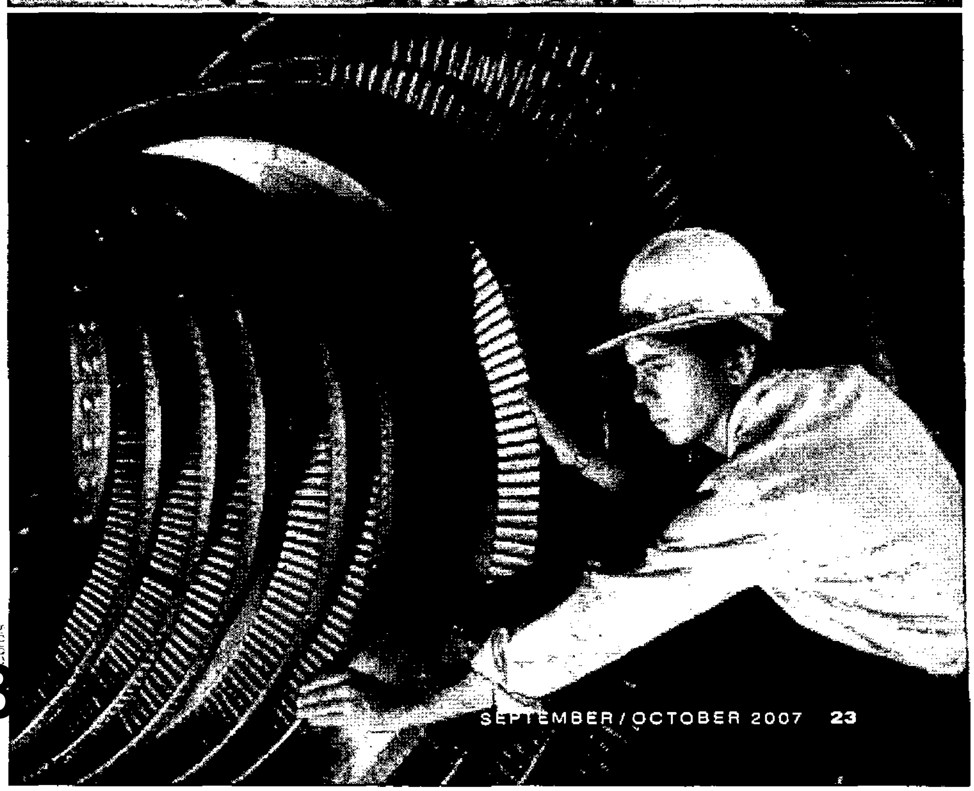
The need for new generating capacity correlates with load growth and projected growth in peak demand. According to the most recent EIA projections, U.S. electricity sales will grow at an annual rate of about 1.4 percent through 2030. The North American Electric Reliability Council (NERC) expects peak demand to grow by 19 percent (141 GW) in the United States from 2006 to 2015. EIA concludes that utilities will need to build 258 GW of new generating capacity by 2030 to meet the growth in electricity demand and to replace old, inefficient plants that will be retired. EIA further projects that coal-fired capacity, which is more capital-intensive than natural gas-fired capacity (the dominant additions to new capacity over the last 15 years), will account for about 54 percent of total additions from 2006 to 2030. Gas-fired plants comprise 36 percent of the total; renewable generators and nuclear power plants will provide the remaining additions (6 percent and 4 percent, respectively). Like coal, renewable and nuclear technologies are capital-intensive with relatively high construction but low operating costs.



builders acquired materials and components before the sharp upturns. The impact is much more dramatic on the estimated cost of proposed projects, which fully incorporate recent price trends. (See the sidebars, "What Are We Building?")

Moreover, these recent increases follow roughly a decade of relatively stable (or even declining) real construction costs, which adds to "sticker shock" both for utilities obtaining cost estimates or bids and for public utility commissions reviewing construction applications. Customers will not feel the full impact of construction cost increases until the utility completes a project, but the issue currently affects the industry's investment plans.

Despite their best estimates just a few years ago, utilities and regulators find themselves face-to-face with these unanticipated increases. How we un-



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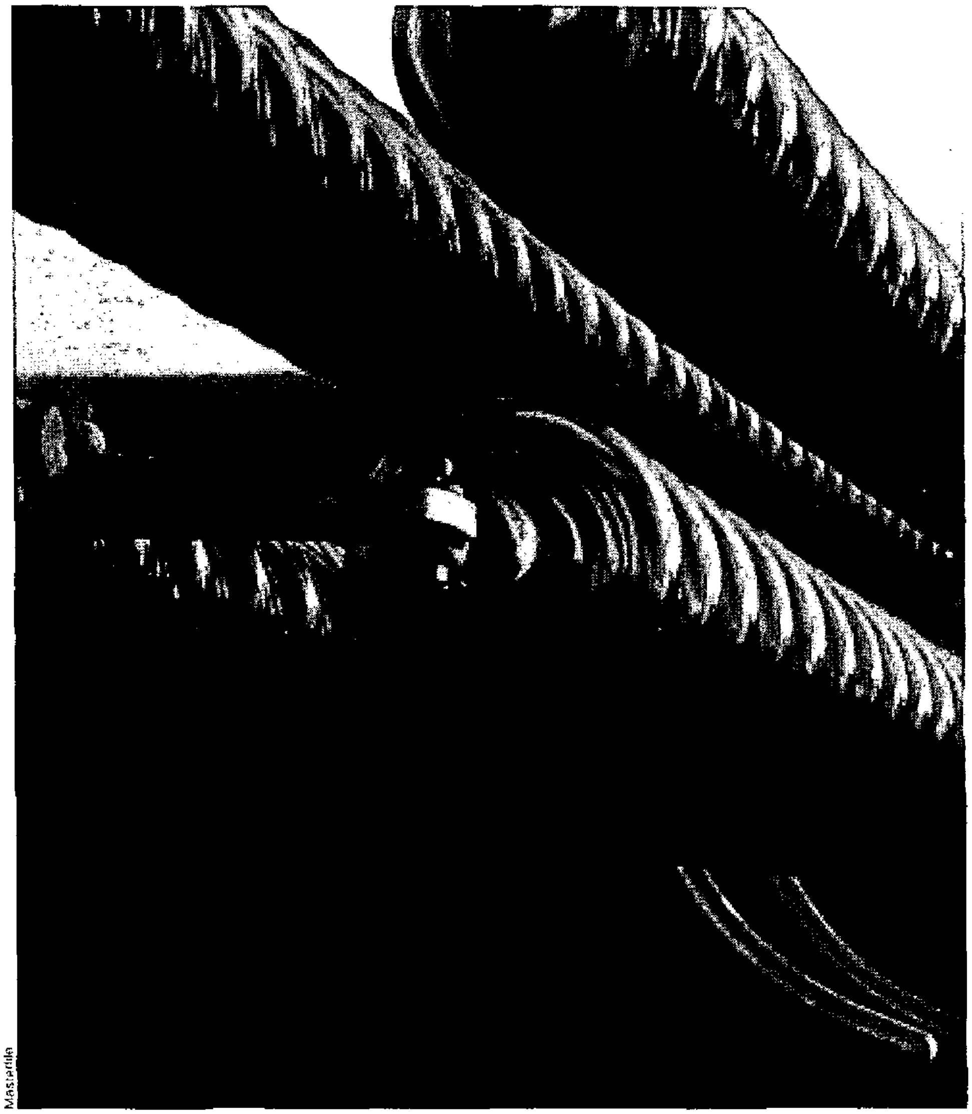
Lines and labor. A few facts for builders of the 13,000 miles of new transmission needed by 2015: Aluminum prices tripled between 2003 and 2006; copper prices nearly quadrupled; skilled labor costs rose 26 percent between 2001 and 2007.



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derstand these construction pressures will be crucial in how we address the next generation of utility investments.

Higher, Now Sharply Higher

Since the 1990s, most of the new generating capacity built in the United States has been either gas-fired—combined-cycle units or combustion turbines—or wind-powered. Both have displayed much higher real costs in recent years.

Prices for gas-fired combustion turbines rose very recently, after years of real price decreases. For installed combined-cycle combustion capacity, however, the increases have been over the past several years. According to a review of commercially available databases and other sources, the average real construction cost of combined-cycle units built in the United States during the last major construction cycle—that is, plants brought into service between 2000 and 2006—was approximately $550 per kilowatt (in 2006 dollars), with a range of costs between $400/KW to approximately $1,000/KW.

Four factors influenced the real installation cost of combined cycle facilities: plant size, turbine technology, the region in which the plant was located, and the commercial online date. Most notable, however, is the significant relationship between a plant's construction cost and its online date: Everything else equal, the later a plant came online, the higher its real cost. The average cost increased gradually between 2000 and 2003, rose fairly significantly in 2004, and then escalated a great deal—more than $300/KW—in 2006. This sharp rise outpaces inflation: Over the same period, the cumulative increase in the general price level was 16 percent while the cumulative increase in the installation cost of new combined-cycle units was almost 95 percent, with much of this increase occurring in 2006.

The costs for wind generation have risen recently as well. In a July 2006 report, for example, the Northwest Power and Conservation Council (NPCC), which prepares long-term electric resource plans for the Pacific Northwest, found that the cost of new wind projects rose substantially in real terms in the two previous years and was much higher than NPCC assumed in its most recent resource plan. The lifecycle cost of power from new wind projects rose by 50-70 percent, which NPCC attributed to higher construction costs. According to the council, the construction cost, in real dollars, has increased from about $1,150/KW to $1,300-$1,700/KW in the past few years, with an average capital cost of wind projects in 2006 at $1,485/KW. Some factors contributing to this rise include a weakening dollar, escalation of commodity and energy costs, and increased demand for wind power under renewable portfolio standards in many states. NPCC notes that commodities used in the manufacture and installation of wind turbines and ancillary equipment, including cement, copper, steel, and resin, have experienced significant cost increases in recent years.

In a May 2007 report, the Department of Energy (DOE) found that prices for wind turbines (the primary cost component of installed wind capacity) rose by more than $400/KW between 2002 and 2006, nearly a 60-percent increase.

Upward Trajectories

But the most dramatic cost escalations are found in proposed utility investments, because they fully reflect the recent, sharply rising prices of construction and installation costs.

The effects on generation proposals are the most visible. Consider the significant construction cost increases in recent utility applications for regulatory approval to build coal-fired plants. Otter Tail Power, for example, leads a consortium of seven Midwestern utili-

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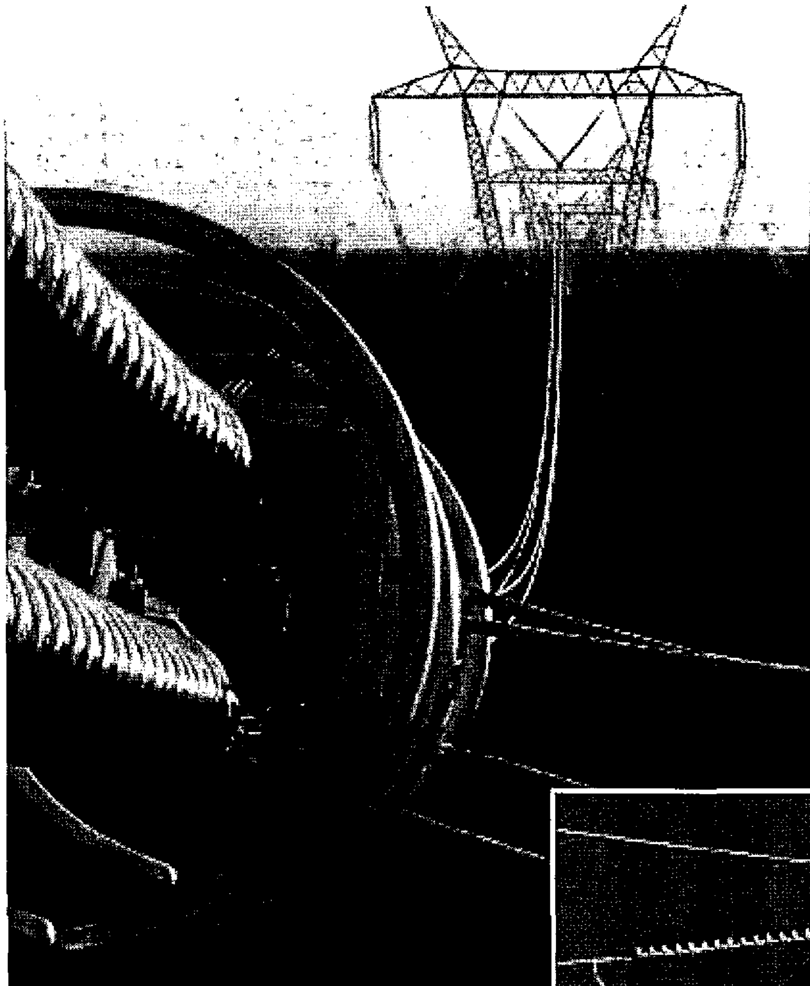


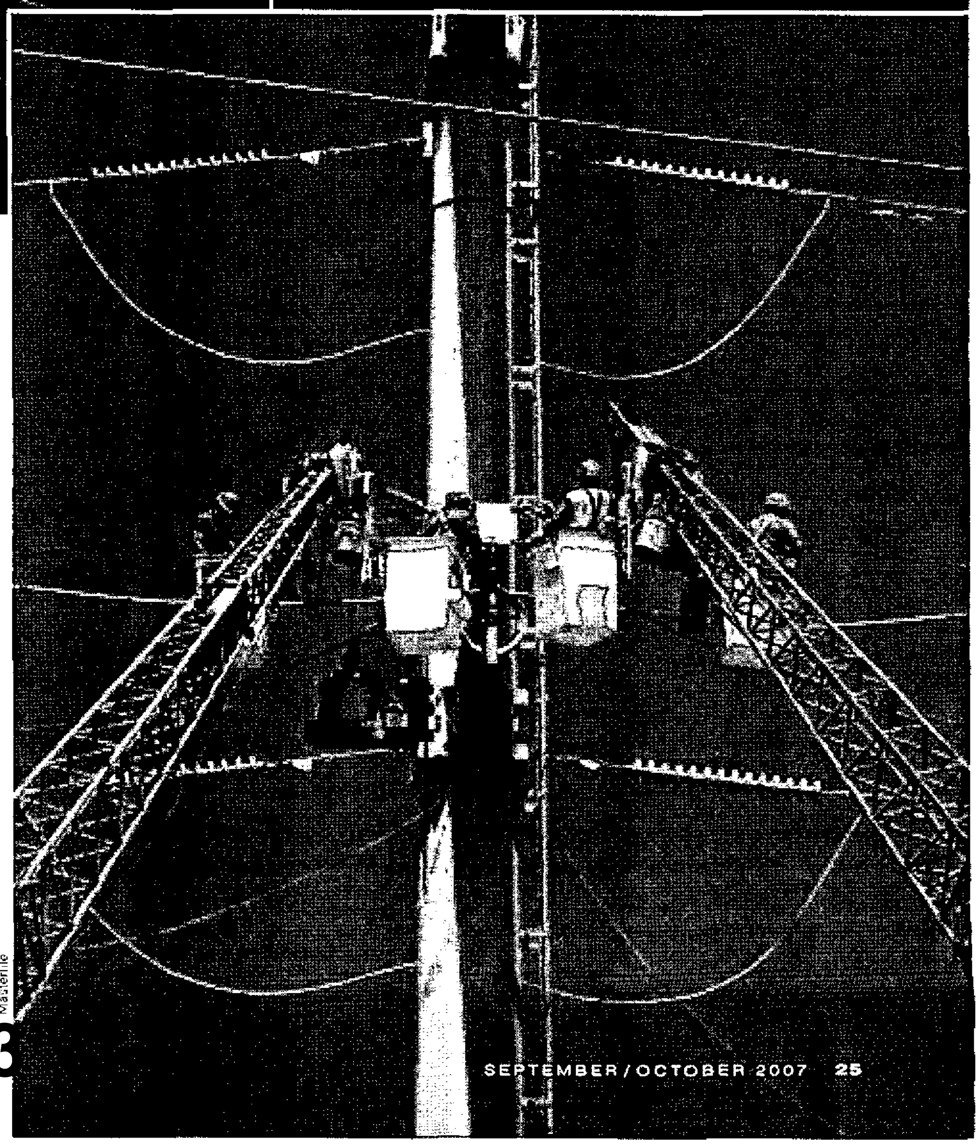
Transmission:
What Are We Building?

ransmission investment began a significant upward trend in 2000. Between 2000 and 2006, shareholder-owned electric utilities and stand-alone transmission companies have invested more than $32 billion in the transmission system. In 2006 alone, the industry invested $6.9 billion, with $8.0 billion estimated during 2007. A recent Edison Electric Institute survey shows that its members plan $31.5 billion in transmission investment from 2006 to 2009, a nearly 60-percent increase over the 2002-2005 period. One reason for this surge is the large amount of new baseload generation built farther from load centers, creating a need for larger and more costly transmission projects compared to those of the past 20 years. In addition, new government policies and industry structures are enhancing the ability to invest in transmission.

NERC projects that utilities will add 12,873 miles of new transmission by 2015, an increase of 6.1 percent in the total miles of installed extra-high voltage lines in North America. (NERC notes that this expansion lags demand growth and expansion of generating resources in most areas. However, NERC's figures do not include several major new transmission projects proposed in the Pennsylvania-New Jersey-Maryland (PJM) Interconnection.)

ties that wants to build a 630-MW coal-fired unit on the site of the existing Big Stone Plant in South Dakota, along with a new high-voltage transmission line to deliver power from both the new plant and other sources, including possibly wind and other renewable forms of energy. In June 2005, the initial estimate for the power plant was about $1 billion, with an additional $200 million for the transmission line. However, those estimates increased dramatically after design changes required a second proposal. While other factors were involved (making changes to boost the unit's output and efficiency and raising the voltage of the proposed transmission line), the cost increase was largely due to higher costs for construction materials and labor. The consortium now expects the entire project to cost $1.6 billion.

In June 2006, Duke filed for a certificate of public convenience and necessity for the construction of two 800-MW coal-fired units at the utility's Cliffside



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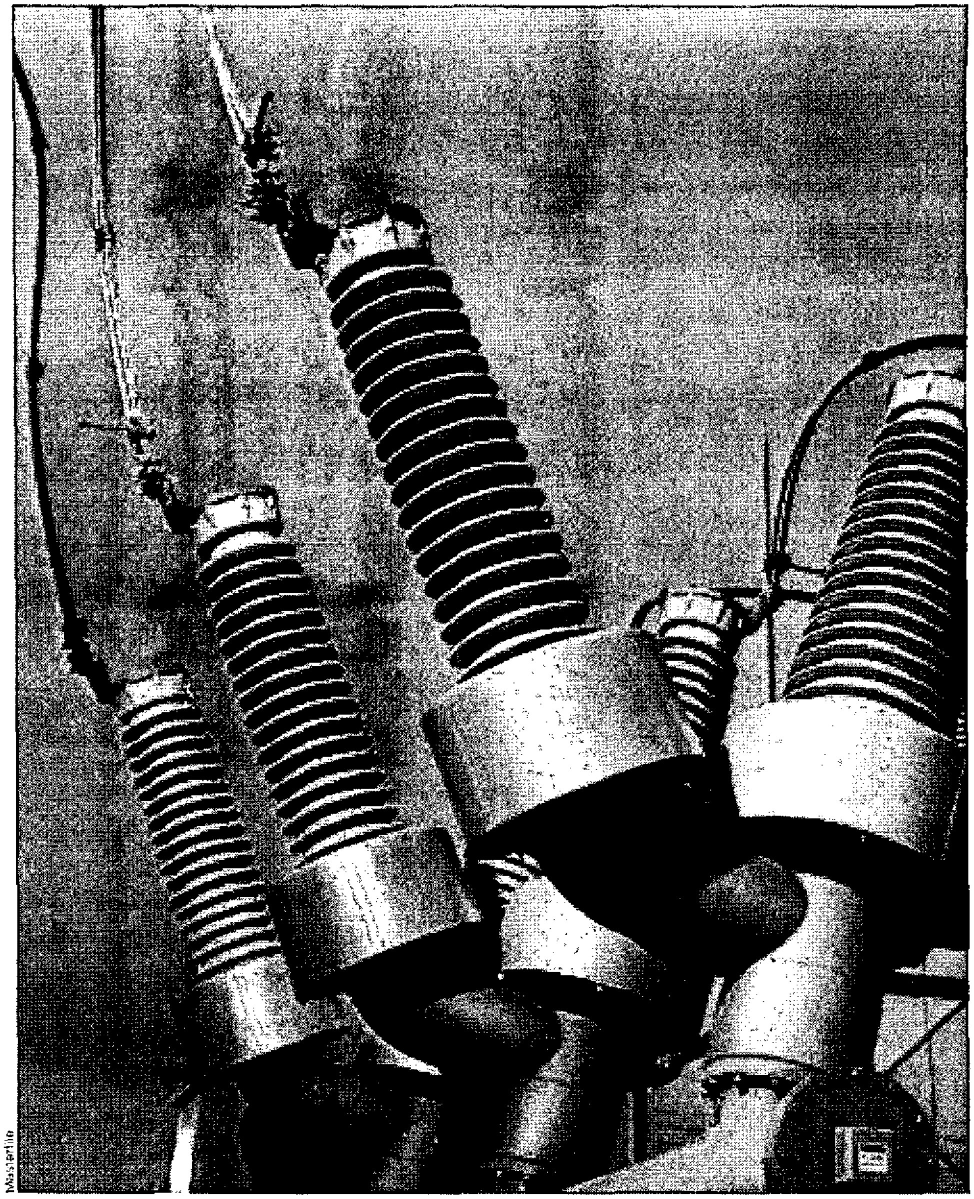
No insulation. Between 2004 and 2007, distribution infrastructure costs rose at a faster pace than generation and transmission. Prices of line and pad transformers, for example, went up 68 percent and 79 percent, respectively. And overhead conductors went up by 34 percent.



Steam Station in North Carolina. In its initial application, Duke estimated a construction cost of $2 billion, based on a May 2005 projection. Five months later, the company submitted a second filing with a revised estimate of $3 billion. The North Carolina Commission approved the construction of one unit at Cliffside but disapproved the other, primarily on the basis that Duke had not shown that it needed the capacity to serve projected growth in native load. The utility's estimate for building one unit at Cliffside is $1.8 billion—about $2,250/KW. With the financing charges and allowance for funds used during construction, the estimated capital cost is $2.4 billion (or about $3,000/KW).

Rising construction costs have led utilities to reconsider expansion plans even before the commission gets involved. In December 2006, Westar announced that it was deferring consideration of a 600-MW coal-fired facility due to significant increases in construction estimates—from $1.0 billion in May 2005 to about $1.4 billion a year and a half later.

Increased construction costs are also affecting proposed demonstration projects. For example, the DOE announced earlier this year that the projected cost for FutureGen, its most prominent clean-coal demonstration project, had nearly doubled. (FutureGen is a public-private partnership involving DOE, industrial coal producers, and electric utilities to build an advanced integrated coal gasification combined cycle plant aiming for near zero emissions of sulfur dioxide, nitrogen oxides, carbon dioxide, and particulates.) The initial estimate was $950 million. After re-evaluating the cost of construction materials, labor, and inflation, DOE put the price at $1.7 billion.

Higher Wires

To enhance reliability and improve import capability into Boston, a heavily transmission-constrained "load pocket," NSTAR Electric is building two 345-kilovolt lines from Stoughton, MA, to substations in Boston's Hyde Park section and South Boston, respectively. In an August 2004 filing before ISO-New England (the grid's independent system operator), NSTAR indicated that the project would cost $234.2 million. In March 2007, NSTAR informed ISO-NE that estimated costs had increased by almost 25 percent to $292.0 million. NSTAR attributed the rise to jumps in both construction and material costs. Construction bids came in at 24 percent higher than initially estimated: Copper had increased by 160 percent, core steel by 70 percent, flow-fill concrete by 45 percent, and dielectric fluid (used for cable cooling) by 66 percent.

Transmission projects require land, and in many areas of the country land prices have increased substantially over the last few years. In March 2007, the California Public Utility Commission approved construction of a 25.6-mile, 500-KV line between Southern California Edison's (SCE's) Antelope and Pardee substations. SCE initially estimated $80.3 million for the line. As California real estate prices rose, so did the cost of right-of-way: The company subsequently revised its estimate to $92.5 million, an increase of more than $3.5 million per mile.

Distribution Equipment Costs Rise

Most distribution projects are small relative to those for generation and transmission (which are more visible and public) and therefore receive less scrutiny on a project-by-project basis. But costs have been rising in this sec-

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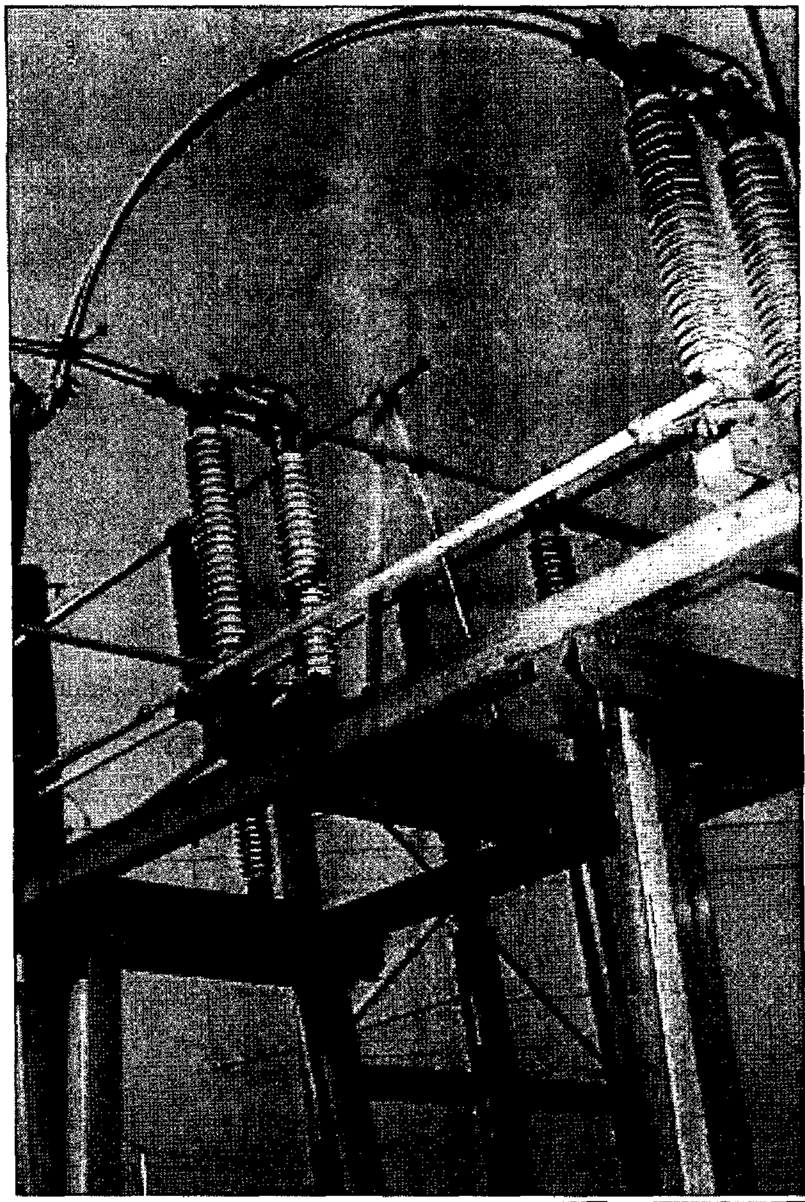
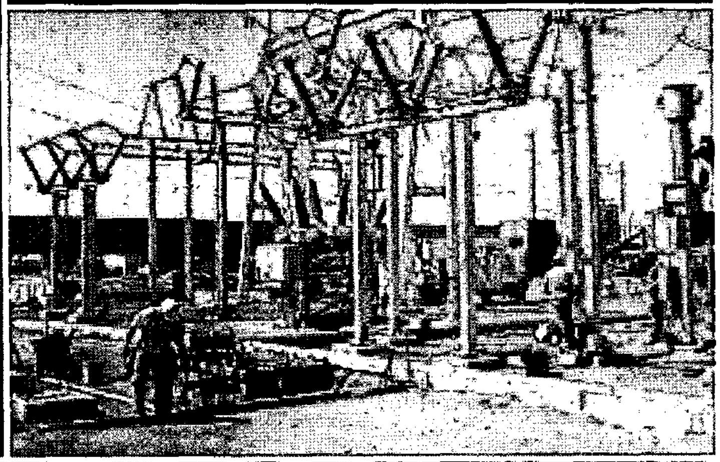


Distribution:
What Are We Building?

tilities require continual investment in distribution facilities—from poles and transformers to metering, billing, and other related infrastructure and software—to keep pace with growth in customer demand. In real terms, investment began to increase in the mid-1990s, and the steady climb in investment shows no sign of diminishing. The needs to replace aging infrastructure, address increased population growth, and meet demand for power quality and customer service continue to motivate utilities. In 2006, utilities invested about $17.3 billion in upgrading and expanding distribution systems, a 32-percent increase over 2004 investment levels. Edison Electric Institute projects that distribution investment during 2007 will total about $21.8 billion, nearly a 50-percent increase over the previous year. While much of the recent increase in distribution investment reflects expanding physical infrastructure, a substantial portion is due to the increased input costs of materials and labor.



tor, as well. According to the Handy-Whitman Index (which tracks costs in all areas of construction), several important categories of distribution equipment and components have seen large price increases over the past three years. For example, the prices of line transformers and pad transformers went up by 68 percent and 79 percent, respectively, between January 2004 and January 2007, with increases during 2006 alone of 28 percent and 23 percent. The cost of overhead conductors and similar devices went up by 34 percent; the cost of station equipment, 38 percent. These are in contrast to the overall price increases of roughly 8 percent over the past three years.

The Sum of the Parts

Utility construction projects involve large quantities of aluminum, copper, and steel (and components manufac-

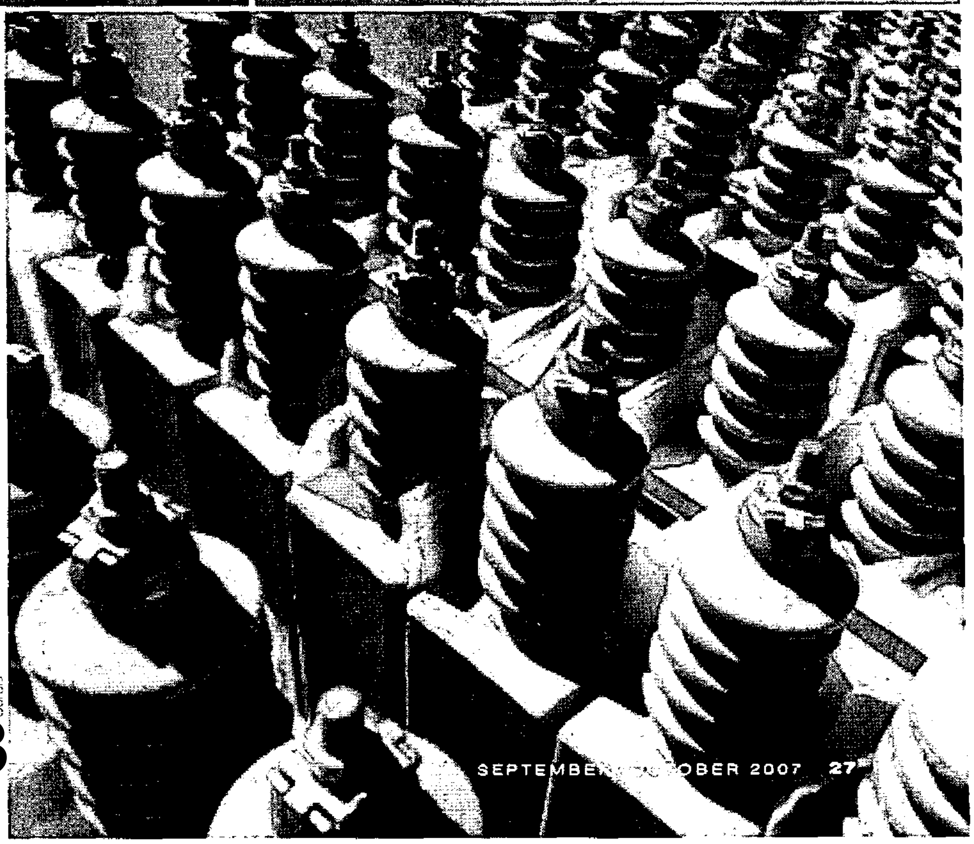


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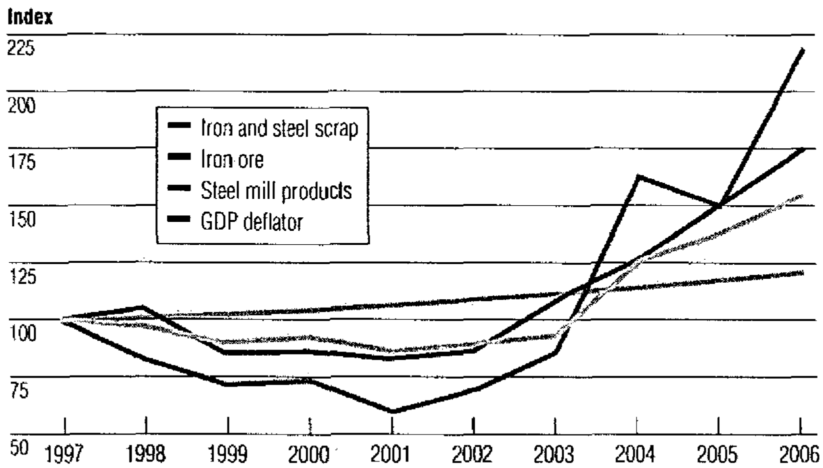
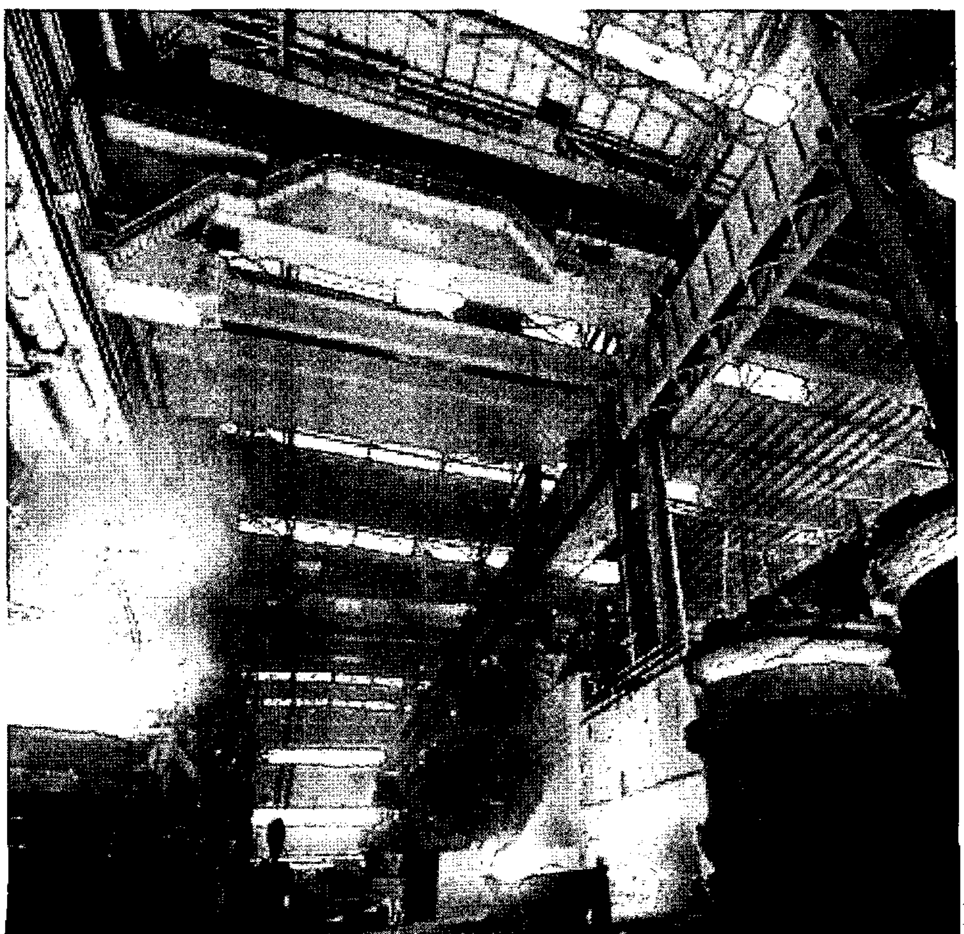
FIGURE 1
IRON AND STEEL PRODUCTION INPUTS AND STEEL MILL PRODUCTS PRICES
(Index: 1997=100)



Sources: U.S. Geological Survey, Mineral Commodity Summaries, and U.S. Bureau of Economic Analysis.



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UNDERSTANDING THE GDP DEFLATOR

The gross domestic product deflator in many of the accompanying figures measures the changes in the overall cost of goods and services purchased by households, industry, and government and serves as a measure of inflation. It is a broader price index than the consumer price and producer price indices, which track the costs of goods and services purchased only by households and by industry, respectively.

tured from these metals), as well as cement for foundations, footings, and structures. Prices for those commodities had been relatively stable for many years, even declining in real terms. But high domestic and global demand and increased production costs (in mining, transportation, and energy) have pushed up prices dramatically. A weakening U.S. dollar has also contributed to high domestic prices for imported materials and major component products: Although the dollar appreciated against other major trading partner currencies between 1997 and 2001, it has lost 20 percent of its value since 2002.

The price of iron and steel scrap and iron ore fell in real terms during the late 1990s but rose sharply after 2002. (See Figure 1.) Compared to the 20-percent increase in the general inflation rate between 1997 and 2006, iron ore prices rose 75 percent, and iron and steel scrap prices rose nearly 120 percent. (See the sidebar, "Understanding the GDP Deflator.") The increase over the last few years was especially acute—between 2003 and 2006, prices for iron ore rose 60 percent and iron and scrap steel rose 150 percent.

The increase in input prices shows up in steel mill product prices, which have increased about 60 percent since 2003. The Congressional Research Service (CRS), which issued a report on steel prices and related industry issues in August 2006, points to the rapid growth of steel production and de-

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mand in China as the primary causes. China has become the world's largest steel maker and the world's largest steel consumer. In addition, CRS contends that steel companies have achieved much greater pricing power, partly through industry consolidation. The CRS report further notes that, in 2006 more so than in the past, what drove demand for steel were products used in energy and heavy industry, such as plate and structural steels.

From the steel industry's perspective, the rapid increase in prices of steel inputs (and not just scrap and iron ore, but also coking coal and natural gas fuel) justifies the substantial rise in prices for the finished product. Today's steel prices are at historically high levels—and it appears they will remain there at least for the near future.

Other metals display similar price patterns: declining real prices over the first five years or so of the previous ten years, followed by sharp increases in the last few years. Aluminum prices doubled between 2003 and 2006; copper prices nearly quadrupled. (See Figure 2.) Metals that contribute to important steel alloys, such as nickel and tungsten, follow similar patterns.

Large infrastructure projects require huge amounts of cement, as well as basic stone materials. Like the price of metals, the price of cement has also risen substantially in the past few years and for much the same reason: It is an internationally traded, energy-intensive product that faces powerful global demand. (See Figure 3.) Utility builders often combine cement with stone and other aggregates for concrete (often reinforced with steel); there are other construction site uses for sand, gravel, and stone, as well. Increased energy costs in extraction and transportation have put pressure on stone prices, which have increased about 30 percent between 2004 and 2006.

While large utility construction projects use many unassembled or semi-finished metal products (reinforcing bars for concrete, for example, and structural steel), such components as conductors and transformers are manufactured elsewhere and shipped to

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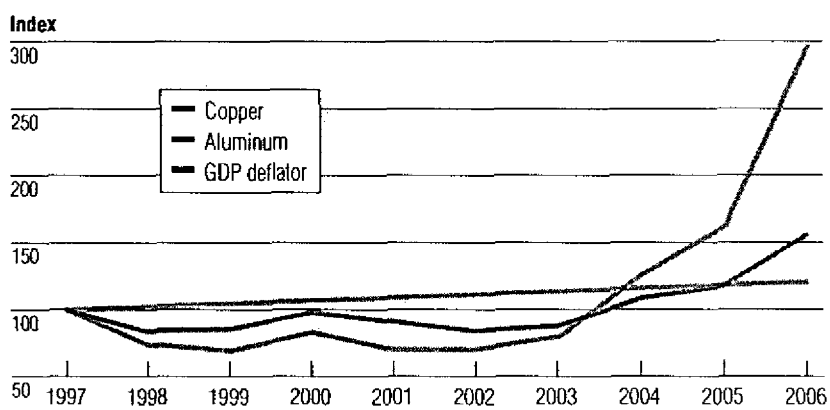
FIGURE 2
ALUMINUM AND COPPER PRICES
(Index: 1997=100)



Sources: U.S. Geological Survey, Mineral Commodity Summaries, and U.S. Bureau of Economic Analysis.

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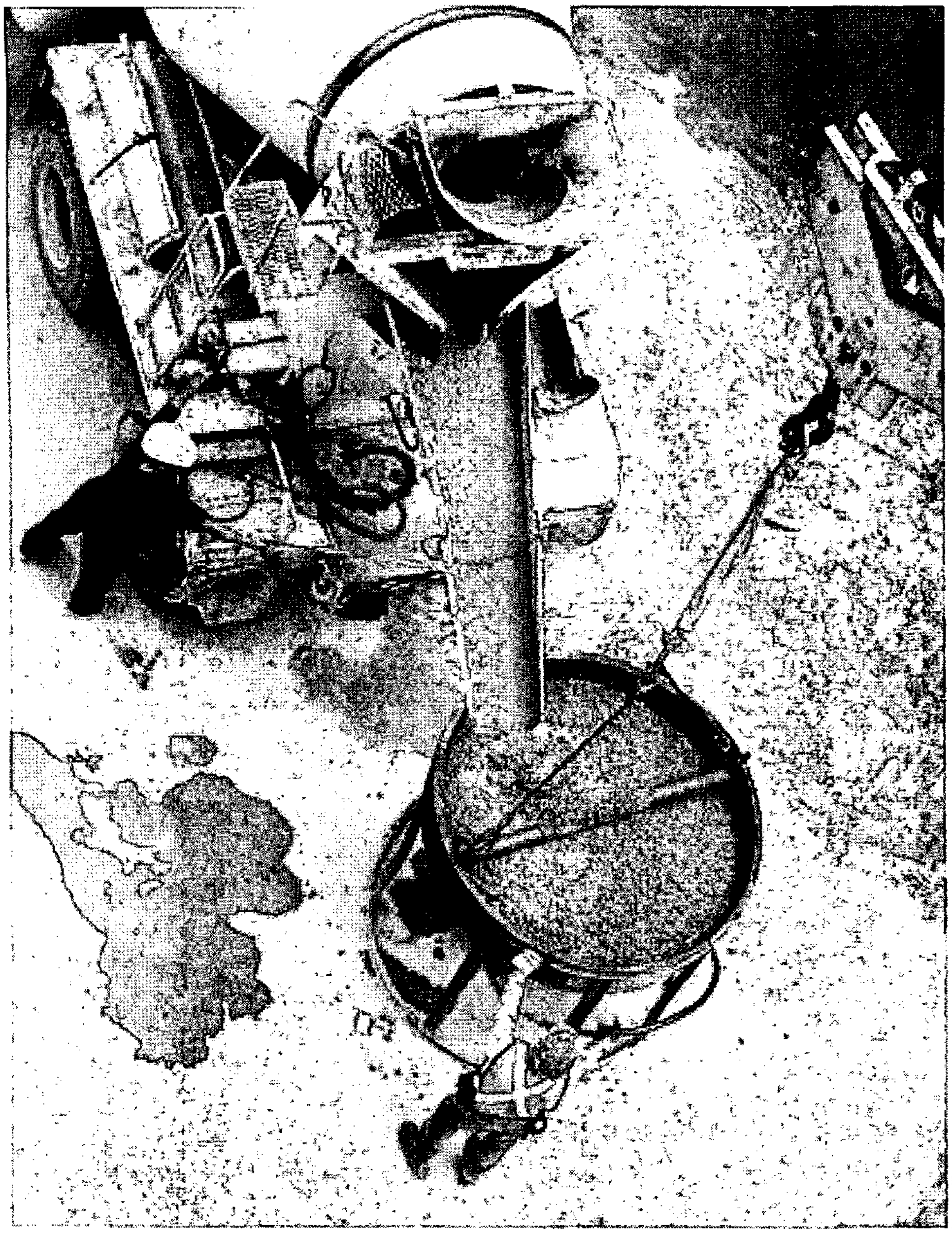

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the construction site. Prices for these components display similar patterns of recent sharp price increases, as do manufactured components of generating facilities—large pressure vessels, condensers, pumps, and valves. (See Figure 4.) Prices for wires tend to follow the upward trend of their underlying metals.

People Who Need People

Labor costs for both unskilled (common) labor and craft labor (such as pipefitters and electricians) have also increased at rates higher than the general inflation rate, but more steadily since 1997 and with recent jumps that are less dramatic than for commodities. (See Figure 5.) Between January 2001 and January 2007, while the general inflation rate increased about 15 percent, the cost of craft labor and heavy construction labor increased about 26 percent, while common labor increased 27 percent. Labor takes up a large share of overall utility infrastructure costs, so even a moderate jump has a significant effect.

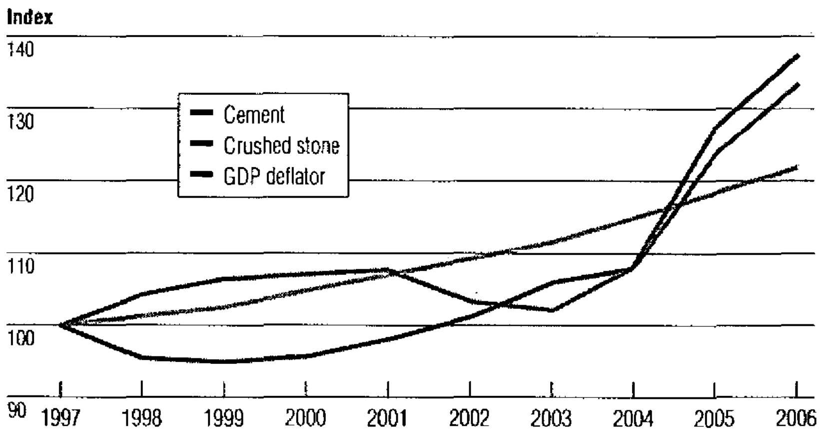
Moreover, there is deep concern about the growing gap between the supply of and demand for skilled construction labor—especially considering utility plans for infrastructure build-out. In 2002, the Construction Users Roundtable found that recruitment, education, and retention of craft workers continue to be critical issues for the construction industry. The average age of the skilled construction workforce is rising rapidly, and the industry's high attrition rates—not only at the entry level, but also among many workers in the 35- to 40-year-old age group—compound the problem. The latest projections are that the construction industry must recruit 200,000 to 250,000 new craft workers per year to meet future needs. Demographics are working against that effort.

There also could be a growing gap between the supply of and demand for electrical lineworkers—who erect poles and transmission towers, install and repair cables and wires, and generally perform much of the labor for transmission and distribution investments.

FIGURE 3

CEMENT AND CRUSHED STONE PRICES

(Index: 1997=100)



Sources: U.S. Geological Survey, Mineral Commodity Summaries, and U.S. Bureau of Economic Analysis.

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According to a DOE report, demand for such workers will outpace supply over the next decade, revealing a shortage of as many as 10,000 lineworkers, or nearly 20 percent of the current workforce. As of 2005, lineworkers earned a mean hourly wage of $25 an hour, or $52,300 per year. To attract more lineworkers, those wages will have to rise.

Not in Stock

Many of the components of utility projects—including large equipment like turbines, condensers, and transformers—are manufactured, often as special orders. Underlying material costs affect their prices, obviously. But most of these components are not part of large inventories, so the overall capacity of their manufacturers (relative to near-term demand) can also influence both the item's price and the length of time between order and delivery. Some of the price increases due to manufacturing capacity constraints are not readily overcome in the near term.

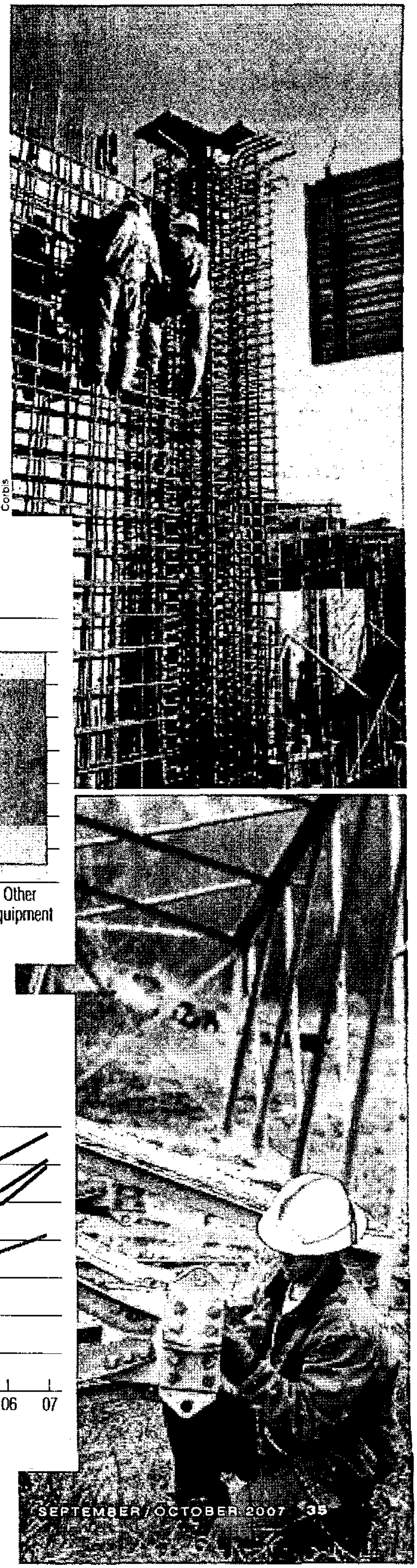
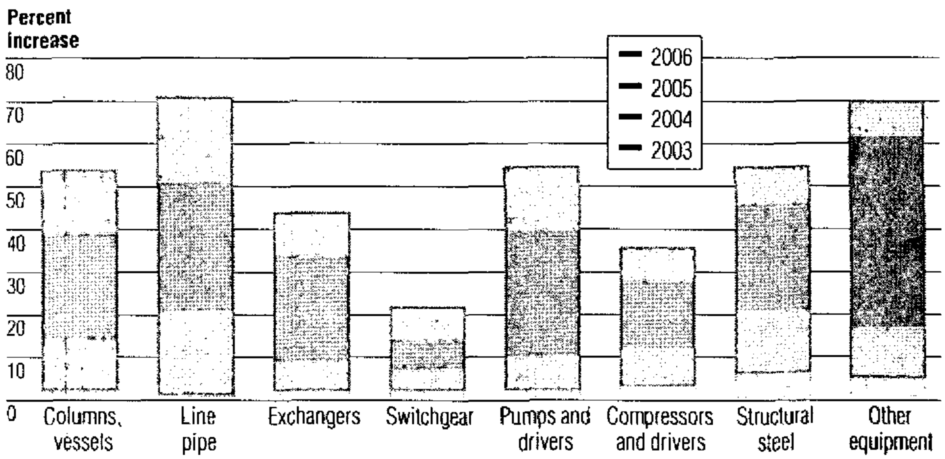
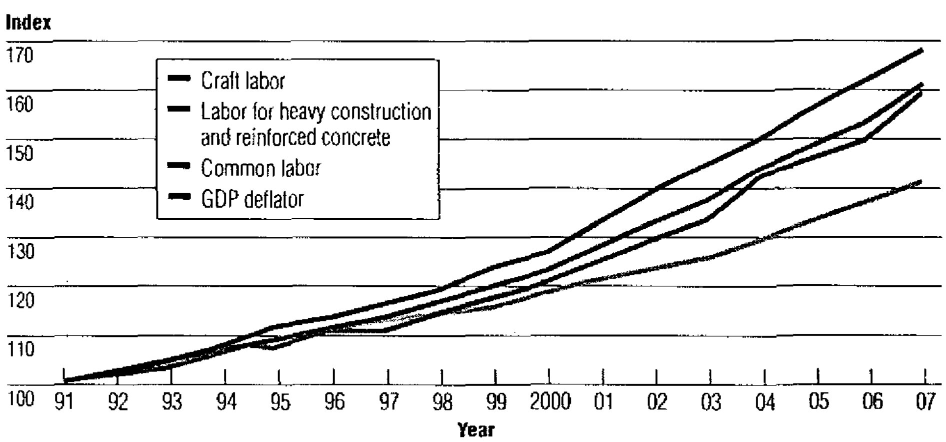


FIGURE 4
POWER PLANT EQUIPMENT PRICES, 2003-2006



Source: Bechtel

FIGURE 5
NATIONAL AVERAGE LABOR COSTS, 1997-2007
(Index: 100=1997)
Simple average of all regional labor cost indices.



Sources: Handy Whitman Index and U.S. Bureau of Labor Statistics

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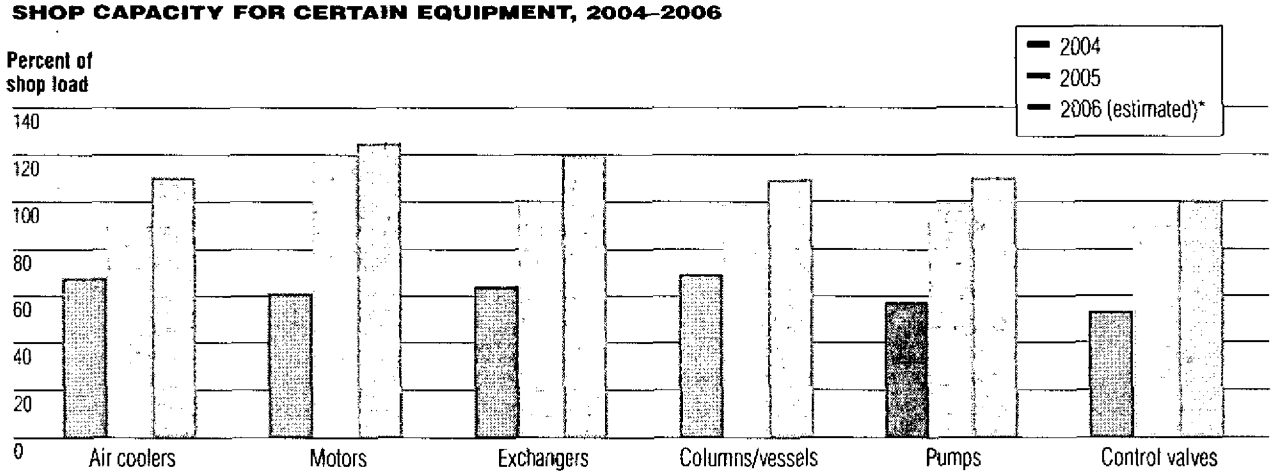
Indeed, recent orders have largely eliminated spare shop capacity, and delivery times for major manufactured components have lengthened. (See Figures 6 and 7.) In addition, these problems are difficult to solve with imported components due to the dollar's lower value in recent years.

Lengthened delivery times can create completion delays that increase the project's financing costs. In general, during a project's construction phase, utilities commit substantial funds that must be financed through either debt or equity. Everything equal, the longer the time from the initiation through completion of a project, the higher the financing costs of the investment and the ultimate cost passed through to ratepayers.

Finding a Contractor

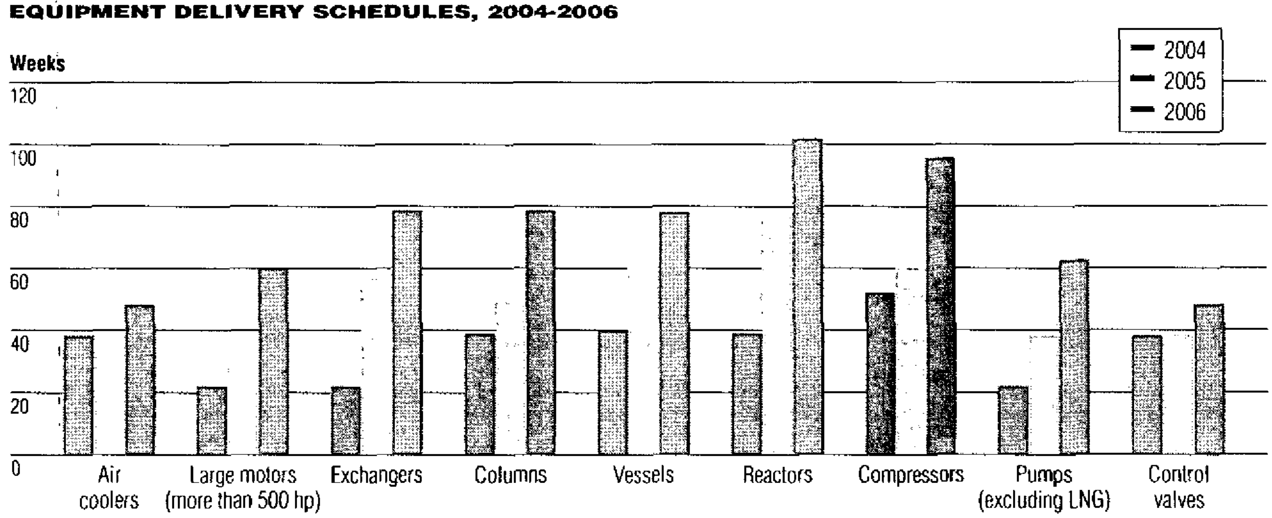
If it is true that worldwide demand for new generating and other electric infrastructure projects, particularly in China, is a significant reason for the recent escalation in utility construction costs, then engineering, procurement, and construction (EPC) firms would probably have a growing project backlog. We could not get specific information from the major EPC firms on what they have in the queue (that is, the number of electric utility projects compared with other infrastructure projects, such as roads, port facilities, and water infrastructure), so we examined their financial statements, which specify the backlog's financial value.

FIGURE 6
SHOP CAPACITY FOR CERTAIN EQUIPMENT, 2004–2006



* Most current reported data. Source: Bechtel

FIGURE 7
EQUIPMENT DELIVERY SCHEDULES, 2004-2006



Source: Bechtel

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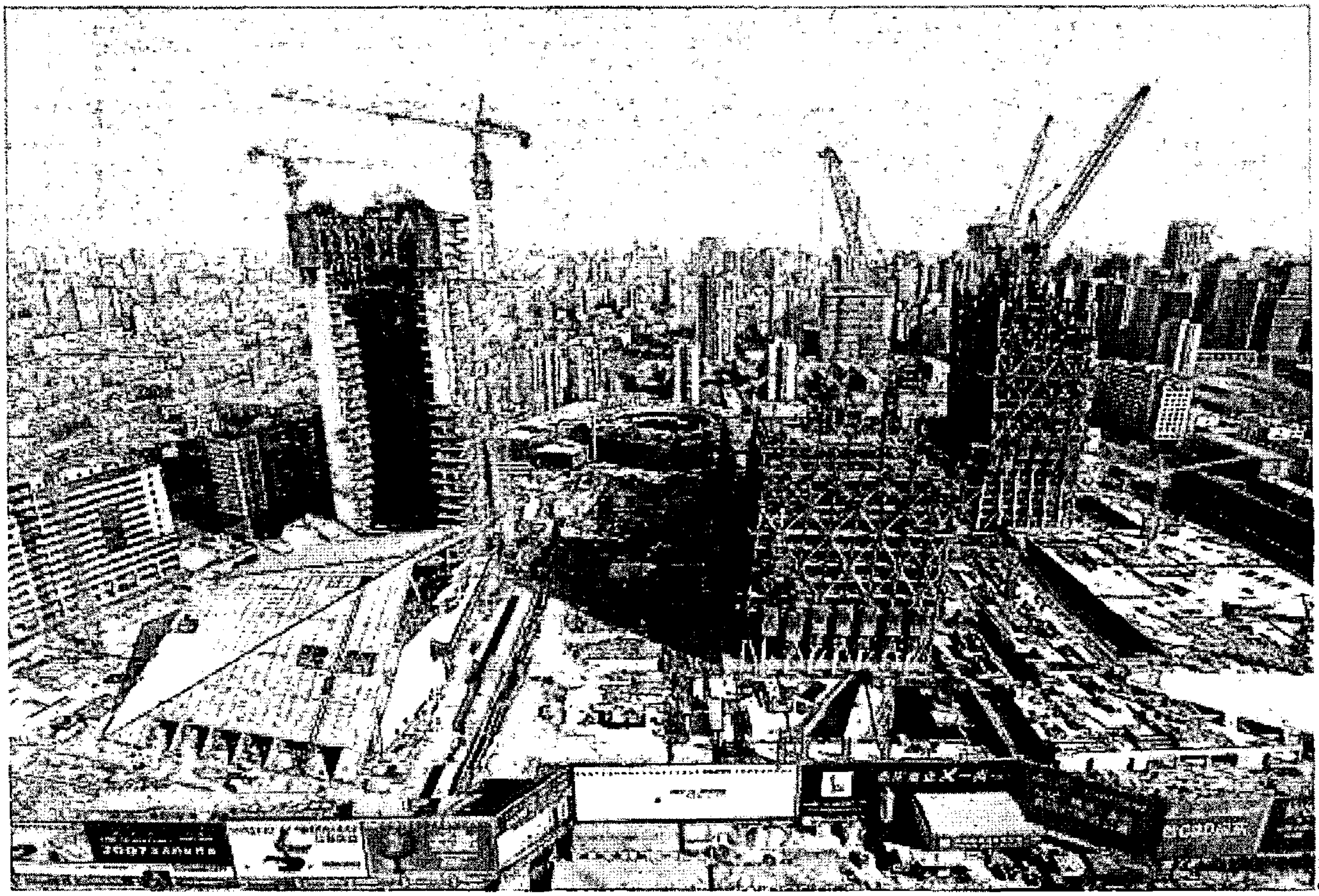

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Big boom. China is the biggest producer and consumer of steel and, with the rest of the world, competes for raw materials.

We found that the value rose sharply between 2005 and 2006, from $4.1 billion to $5.6 billion, an increase of 37 percent. This is consistent with the data showing increased worldwide demand for infrastructure projects in general, including utility generation, transmission, and distribution projects.

That backlog will dampen the competitiveness of EPC bids for future projects, at least until the EPC industry can expand capacity to manage greater volumes of projects. This is not to suggest that this market is uncompetitive. Rather, it reflects the limited ability of EPC firms with constrained near-term capacity to service an upswing in new project development during a boom period in infrastructure construction cycles. There is little incentive to bid aggressively on new projects when the queue is already filled.

Although difficult to quantify, the EPC market's lack of spare capacity will undoubtedly put upward price pressure on new bids for EPC services. We can see this in a January 2007 filing by Oklahoma Gas & Electric (OG&E), which sought approval of the Red Rock plant, a 950-MW coal unit. OG&E noted that it had revised a February 2006 cost estimate of nearly $1,700/KW to more than $1,900/KW by the end of September 2006—a 12-percent increase in just nine months. The utility ascribed more than half of the increase (6.6 percent) to changes in market conditions regarding not only materials and equipment costs, but also "a significant tightening of the market for EPC contractor services (as there are relatively few qualified firms that serve the power plant development market)." OG&E's estimate for EPC services had increased by more than half in nine months—from $223/KW to $340/KW.

Construction Indices: A Pattern of Recent Jumps

Several sources publish indices that reflect composite costs for various construction projects. Although differences in these indices depend on assumptions about weighted costs (for labor, materials, and manufactured components, for example), they provide useful summary measures for large infrastructure projects.

RS Means, for example, provides a construction cost index that primarily addresses building construction (as opposed to utility projects) but reflects many of the shared cost drivers, such as steel, cement, and labor. While the index rose slightly higher than the GDP deflator beginning in the mid-1990s,

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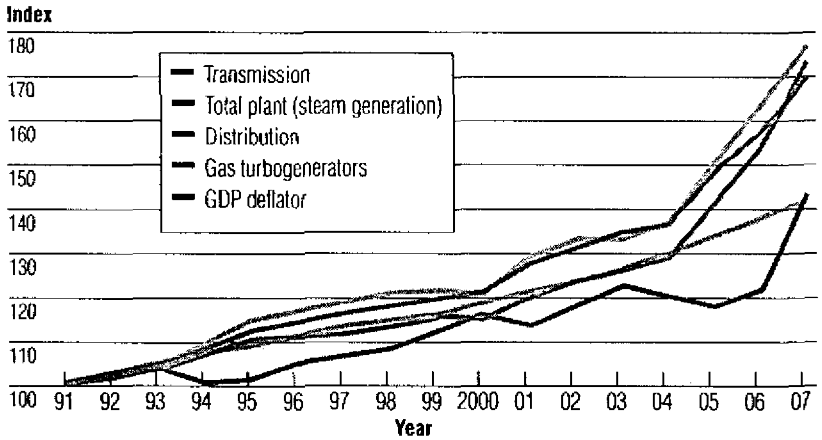
FIGURE 8

NATIONAL AVERAGE UTILITY INFRASTRUCTURE COSTS, 1991-2007

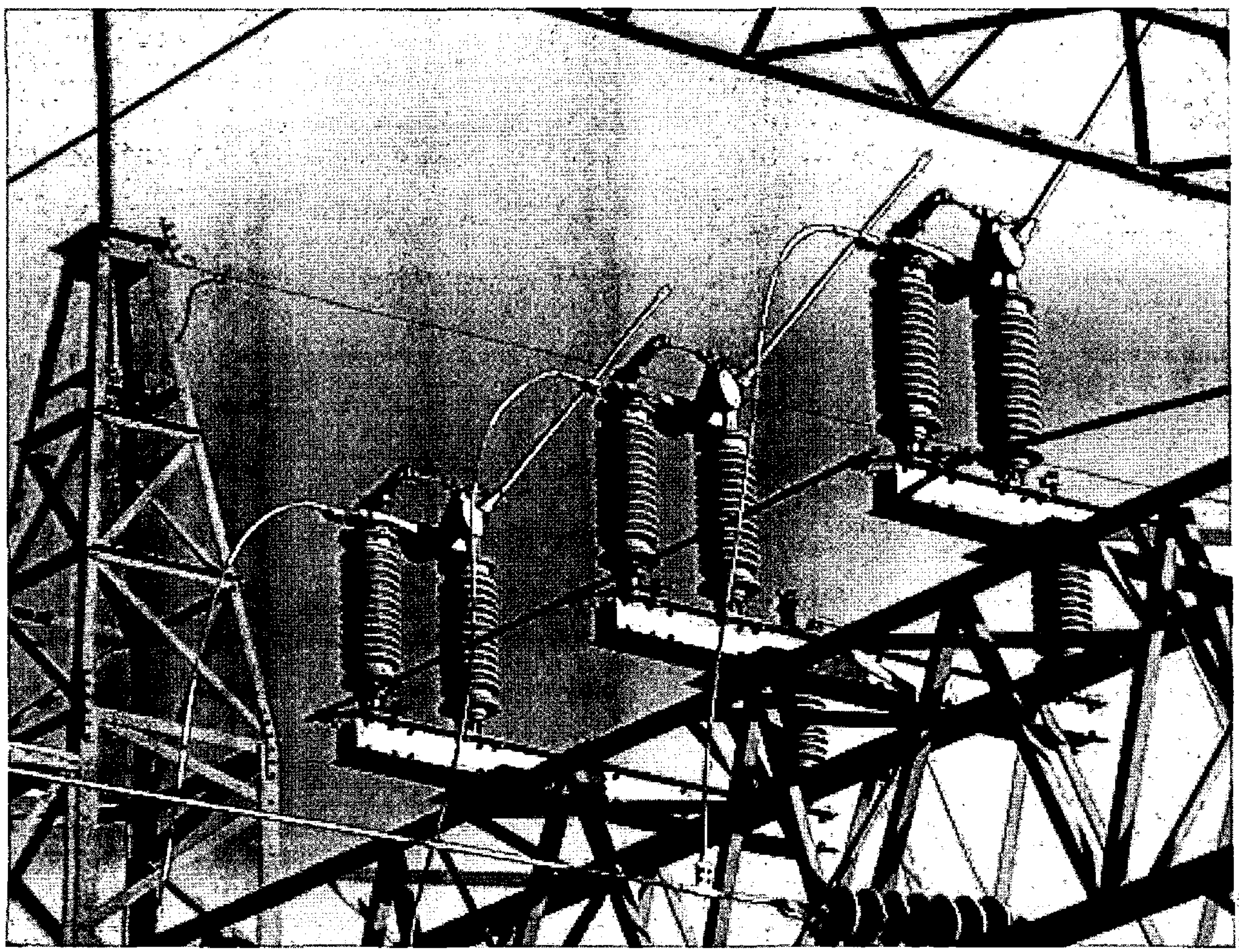
(Index: 1991=100)



Sources: Handy Whitman Index and U.S. Bureau of Labor

it shows a pronounced increase between 2003 and 2006, when it rose by 18 percent (compared to the 9-percent increase in the general price level).

The Handy-Whitman Index publishes indices of utility construction costs—often broken down by detailed component costs—for six regions. (See Figure 8.) Steam generation construction costs (for boilers, generators, piping, etc.) tracked the general inflation rate fairly well through the 1990s, began to rise modestly in 2001, and have increased significantly since 2004. Between January 1, 2004, and January 1, 2007, the cost of building steam generation increased by 25 percent—more than triple the inflation rate. Costs for gas-fired combustion turbines actually fell between 2003 and 2005, but during 2006 the cost of new turbines increased



APPENDIX 3

AP Images

by nearly 18 percent—roughly 10 times the inflation rate.

The cost of transmission plant investments (for towers, poles, station equipment, conductors, and conduit) more or less tracked inflation between 1991 and 2000, increased significantly in 2001, and then showed an especially sharp increase between 2004 and 2007, rising almost 30 percent and nearly four times the inflation rate. Overall distribution plant costs (for poles, conductors, conduit, transformers, meters, and so on) stayed close to the inflation rate until 2004, then increased by 34 percent between January 2004 and January 2007, a rate that exceeded four times that of inflation.

By Any Other Measure

EIA's 2007 "Annual Energy Outlook" indicates that construction costs since 2004 have generally tracked inflation and will in future, but recent experi-

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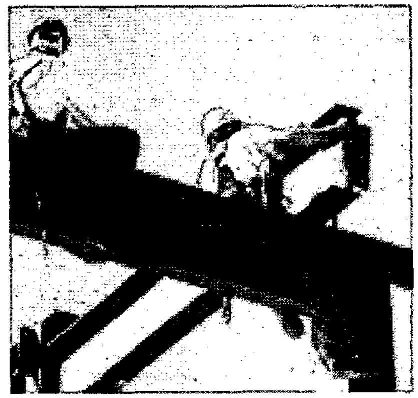


Along with its "Annual Energy Outlook," the Energy Information Administration (EIA) prepares a report on the assumptions (about fuel prices, economic growth, environmental regulation, and so forth) that underlie the 25-year forecast. Aside from reflecting regional labor conditions, the assumptions are generic and do not take into account a project's site-specific characteristics. But in theory EIA's assumptions support a ballpark estimate of the relative construction cost of different generation technologies at any given time. Industry analysts, consultants, academics, and policymakers use the estimates extensively, and they frequently are cited in regulatory proceedings, sometimes as a yardstick by which to compare a utility's projected or incurred capital costs for a generating plant.

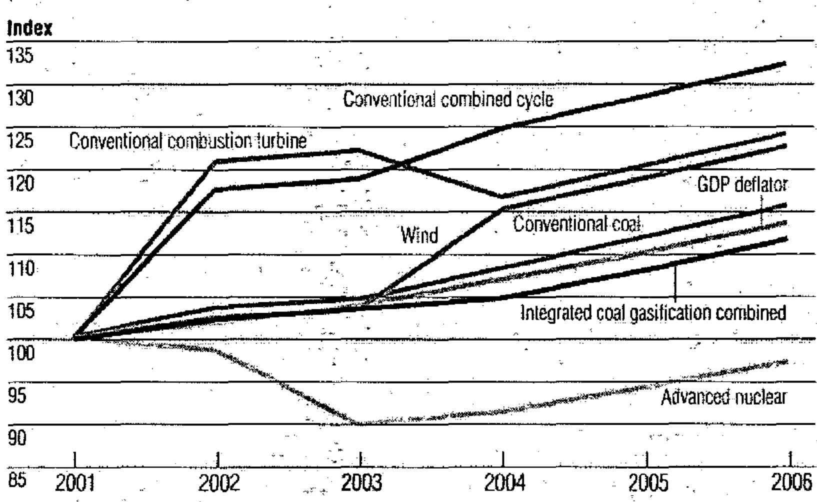
But are the data adequately taking into account current or expected construction costs?

We reviewed EIA's estimate of overnight plant costs (that is, the capital cost exclusive of financing costs) for 2001-06. We focused on the six technologies that have been most commonly built or given serious consideration in utility resource plans in the last few years—combined-cycle gas-fired plants, combustion turbines (CTs), pulverized coal, nuclear, integrated coal gasification combined cycle (IGCC), and wind.

The general pattern in EIA's assumptions shows a dramatic change in several technology costs between 2001 and 2004, followed by a stable period of growth until 2006. (See the figure.) The two exceptions to this are conventional coal and IGCC, which increase throughout the period by a near-constant rate, close to the rate of inflation. The data show conventional coal and conventional CT experiencing a sharp increase between 2001 and 2002. After this increase, conventional coal cools off and increases at a pace near inflation; conventional CT actually drops significantly before 2004 and also levels off near the rate of inflation. In comparison, nuclear technology falls dramatically until about 2003 and then continues increasing with inflation. Wind moves close to inflation until 2004 when it experiences a one-time jump and then flattens off through 2006.

The pattern (described in this article) for almost all other generation construction cost elements is quite different, however: They show price changes at or near the inflation rate through the early part of this decade, with a dramatic change in only the last few years. EIA itself acknowledges that its estimated construction costs do not reflect short-term changes in the price of commodities (such as steel, cement, and concrete). But for the period that overall construction costs were rising well above the general inflation rate, EIA has not revised its estimated capital cost figures to reflect the trend.

EIA CONSTRUCTION COST ESTIMATES
(Index: 2001=100)



Sources: Energy Information Administration, Bureau of Economic Analysis

ence shows otherwise. (See the sidebar, "What EIA Says.") This is a critical discrepancy, in that utilities and commissions have often relied on EIA projections as cost benchmarks for recent construction proposals, but have found that actual costs have jumped significantly, rapidly, and in a fashion unanticipated just a few years ago. EIA acknowledges that its estimates do not reflect short-term changes in the price of commodities. But increased prices for components, rising wages, and a tighter market for construction management services have also increased the costs of investing in utility infrastructure. These elevated numbers show no immediate signs of abating.

Despite higher costs, utilities will continue to invest in baseload generation, environmental controls, transmission projects, and distribution system expansion. But rising construction costs will put additional upward pressure on retail rates over time and may alter the pace and composition of future investments. The overall impact on the industry and on customers will be borne out in various ways, depending on how utilities, markets, and regulators respond. In the long run, customers ultimately will pay for higher construction costs—directly in rates for the assets of regulated companies; less directly in the forms of higher energy prices needed to attract new generation in organized markets and higher transmission tariffs; or indirectly when rising construction costs defer investments and delay benefits, such as enhanced reliability and lower, more stable long-term electricity prices. ◆

APPENDIX 3