

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

2498 SCOMM○109: JNT. COMM. ELEC. UTILITY○RESTRUCTURING, 1998

JOINT COMMITTEE ON ELECTRIC UTILITY RESTRUCTURING
JANUARY 6, 1999

COMMISSIONER DWIGHT ORNQUIST, APUC: Mr. Chairman I agree with you and we did debate this at quite in depth at the meetings that we have had regarding the one issue that we found very difficult to justify putting it in a regulation, was that a very effective argument is made by utilities is made that they already have difficulty collecting when the bills are high and working with the customers. If we put it in regulation or in law that they could not be cut off the point was that a lot of people would not be paying all winter long. And then the cost continues to fall to the people who do pay their bills to make up for that. The APUC would be open to direction and guidance from the Legislature on this.

CO-CHAIR ROKEBERG: Representative Davies and then we will wrap this up. Forgive me for bringing.....for opening Pandora's box.

REPRESENTATIVE DAVIES: Appreciate this discussion, what I want to know is.....tell me what the concept of universal service is?

COMMISSIONER ORNQUIST: Universal service is the idea that anybody who wishes to have service would have access to the system. Just exactly as the Chairman said you have to draw some lines and establish some level at which the existing system supports that growth and where the customer needs to pick up any additional cost of expanding the system to meet that customer.

CO-CHAIR ROKEBERG & REPRESENTATIVE DAVIES: Discuss and debate the concept of universal service and is it available to everybody. Is this low-income subsidy?

CO-CHAIR ROKEBERG: To put a tag on this: In the discussions within the industry any subsidies low income assistance (indisc.) included under the umbrella of universal service by definition. That is why the disclaimer is there. Many jurisdictions provide subsidized electrical service, they put this in their tariff structure. We have power cost equalization programs.

REPRESENTATIVE DAVIES: Goes back to the amendment, line three. Question: Mandate on....long term assistance, conservation programs. Separate issues. Geographical area concerns.

CO-CHAIR ROKEBERG: Will strike amendment six.

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REPRESENTATIVE DYSON: Brings up universal service, when brought up in the past was thinking about how it was defined in telecommunications. "Affordable" is one word that is not in the discussion between Co-Chair & Representative Davies. Need to have a full public policy decision sometime, is there a public responsibility to make sure that power is available for utilities.

CO-CHAIR ROKEBERG: That is why I had the amendment, to introduce the concept.

REPRESENTATIVE DAVIES: Agrees that affordable is inherent with universal service, there is a subsidy involved. But does not differentiate between consumers within a geographic area. Everybody gets the same price, that's the notion of universal service. Inherent subsidy problem.

REPRESENTATIVE DYSON: Agrees got it the first time.

CO-CHAIR ROKEBERG: Chair notes; I have withdrawn the amendment. Amendment 7, any objections? No objections. Amendment 9, any objections? No objections. Amendment 10, any objections? No objections. Page 16, line 1.....line one paragraph 4, Senator Leman, any comments. Will adopt that. Conclusions better take a look at that.

SENATOR LEMAN: Offers as an amendment, the replacement of current recommendation 2 with "my" language which incorporates what "I" am trying to say. Positive way, doesn't commit the Legislature.

CO-CHAIR ROKEBERG: Leave the target date in of March 1?

SENATOR LEMAN: That is currently our target date, we might as well acknowledge it. March 1, 1999.

CO-CHAIR ROKEBERG: Conception amendment is now moved, any objections? No objections, it is adopted to replace recommendation number two. Any further activity or comments? Will schedule the meeting for the 18th at 10:00 am, communicate to the other committee members that they are invited to have their written comments, get a draft out in a timely fashion to everybody. Target no later than Saturday, 16th. Any other comments? Thank you very much, meeting adjourned at 12:20 pm.

The meeting was recorded and handwritten log notes were taken. A copy of the tapes and log notes may be obtained by contacting the House Records Office at 130 Seward Street, Suite 211, Juneau, Alaska 99801-1182, and after adjournment of the second session of the Twentieth Alaska State Legislature in the Legislative Reference Library.



Official Business

COMMITTEE:

EUR

DATE: 1/6/99

SIGN-IN

Subject of meeting:

Discussion
Final Report

PLEASE PRINT!

NAME	ADDRESS (MAILING) & (ZIP)	PHONE	REPRESENTING	DO YOU WANT TO TESTIFY?
MEERA KOHLER	1200 E 1st	263-5202	MLRP	No
DAN HELMICK	1200 E 1st	263-5205	MLRP	No
Paul Morrison	1016 W 6th Ave	274-6222	APUC	No
Bob Lofr	"	"	"	No
Mary Fisher	703 W. Tudor	563-2559	ARECA	No
Jim PATER	1033 'C' St	561-1030	NEA	No
Eric Yould	703 W Tudor Anch	561-6133	ARECA	No
Robin Brenz	310 K St, Suite 601 A	258-2000	Aurora Power	
Mary Ann Pease	310 K Street Suite 601	277-1003	Aurora Power	no
Mike Kelly	Box 71249 FLKS	452-1151	GVEA	
Carol Heyman	5601 Minnesota 99519	762-4707	Chugach	No

COMMITTEE TAPE LOG

PS 1089

COMMITTEE: Joint Comm. Electrical Restructuring DATE: 1/6/99 TIME: 10:27am.
 SUBJECT: Report on RFP for Study, Discussion / Preparation of Final Report of joint Committee (Absent Sen. Taylor, Adams)
 MEMBERS: Present: Sen. Leman, Rep. Davies, Co-Chair Rokeberg, Rep. Dyson,
(Others Rep Hudson)

SPEAKER	TAPE#	SIGNIFICANT INFORMATION
Co-Chair Rokeberg	000/A1	Welcomes members, others delayed. Will ask S. Leman to give report, & then discuss w/ S. Leman comments?
Sen. Leman	018	Reiterates last meeting comments - APUC. Prop. early Dec. 10 reports across country. Selection Comm. - S. Leman, APUC (2) members, 1 company of 10 companies. Had all the 10 pt. requirements. Late this week or early next week firm will be notified of getting the RFP. (Hill - firm chosen)
R. Rokeberg	052	Questions if Comm. APUC case to make comments, (no per APUC)
S. Leman	058	Answers question of teleconf. participant company that will be completing RFP.
R. Rokeberg	066	Thank you S. Leman on yr. hard work - move on to final item on Agenda. Discuss w/ Preparation of final report of joint Committee - mention S. Sharp is getting w/ included in Packet
R. Rokeberg	077	Lead Letter asking if can get, Santer's Janet explain (include in packet)
Janet S.	085	Reiterates, goes forward w/ Draft Recomm.
(P) Rokeberg	090	Brings up amendments & Recomm.
R. Rokeberg	098	Any more comments. Rep. Davies
"	108	Submitted one y's if recommendations -
Davies	111	ask to add comments, dissent, etc. of members - Don't have
Rokeberg	115	

SPEAKER	TAPE #	SIGNIFICANT INFORMATION
		formal quorum. Take comments, finalize report after session starts
R. Robbers	126	objection's
S. Leman	127	okay w/ me.
R. Davies	131	no objection
R. Dyson	133	fine
R. Robbers	137	meeting afternoon of the 18th to finalize. Meeting at ...
R. Robbers	141	Brief at ease. (2 minutes) calls back to ...
R. Robbers	141	Tent. meeting 10:30am. Mon. 18th
		Farenkamp Rm. possible.
R. Robbers	150	When can we get out, depending on Comp.
S. Leman	153	Comp's, fares are packed how to get ...
R. Robbers	157	I have fax - email or Janet has
R. Davies	160	Time line.
R. Robbers	164	Leaving 14th, fax or email me 248-7309, Robbers at AK.net
		243-1454 phone call when e-mailing
R. Robbers	177	move back to body of report, any comments
R. Davies	182	no prob. A. merid.
R. Robbers	184	Any corrections, objections appreciated
R. Davies	187	any dozen marginal comments, so thru.
R. Hudson	194	pls. move closer ~~to~~ to "mike"
R. Davies	195	apolog(s) makes comments, corrections re residential customers.
R. Robbers	217	Address w/ points. Staff will take of that
R. Dyson	223	handle what?
R. Robbers	225	you that not enough comments Residential

SPEAKER	TAPE #	SIGNIFICANT INFORMATION
R. Dyson	227	Get more comments? Res. Aust.
R. Pikeburg	228	NO. Goes on to overview rest of report.
R. Davies	241	PS 9, 3rd paragraph & 4th para 1st sentence, ^{1st} ~~retail restructuring exercise~~ Strong statements, not clear
R. Pikeburg	264	Rep DYSON
R. Dyson	665	Kindred spirits, agree w/ you now is not the time
R. Pikeburg	273	as author appreciates comments, 3rd paragraph, defend statement. Bring up Area comments, Black, United comments.
R. Dyson	307	suggests modifies, appears in entailed
R. Davies	310	agrees with this
R. Pikeburg	314	Was intentional, to bring up legitimate debate. Several years, there will be restructuring
R. Davies	331	PS 9, few union groups object to competition. He doesn't agree with them. "cherry picking" was brought up.
R. Pikeburg	343	Written letters objecting to
R. Davies	349	Don't feel they will object to competition
R. Pikeburg	355	Doesn't object (Pause)
R. Davies	361	PS 10 3rd sentence, not clear APUC...
R. Pikeburg	373	defends language
R. Davies	376	Don't share view APUC shape feet
R. Pikeburg	377	Defends his opinion, language. 97-201 Docket. Doesn't want to put APUC on spot.
R. Davies	398	(Agree) Some people feel APUC drag it

SPEAKER	TAPE #	SIGNIFICANT INFORMATION
R. Davies	406	Continues APUC waiting, prudent, cautious view....
R. Rokeberg	413	ASK question
D. Davies	414	answers...
Rokeberg	415	statement
both Roke/Davis	416	-----
Rokeberg	417	Expands on report.
Selman.	428	Frustrated; APUC feels they are willing to work with Leg.
Dyson	455	Agrees w/ chairman. APUC has been regulating monopolies. Policy direction needed.
R. Rokeberg	471	Refresh com members, split in industry.
" Rokeberg	500	Will work w/ R. Davies to modify
R. Davies	504	Agrees w/ statement, needs to be modified pg 11, Routhelt, doesn't like "Networks" wants "enteries"
Rokeberg	522	no objections
" "	526	Audience participation &
Davies	530	will get terms
Rokeberg	534	Redundant.?
Selman	540	bothered let experts come up w/ best works
Davies	547	Competition, bothered by:
Rokeberg	572	S. Central area is different from other parts of AB. Bump up parklike
Davies	591	Related comments, hope not practice pg 12 CENS probable, com members each make comments on this.
Davies	000/B	Continues w/ suggestions, Red flag, level of summary?

SPEAKER	TAPE #	SIGNIFICANT INFORMATION
Rokeberg	008	Dismisses in 3 words suggestions
Dyson	012	up. wording is brilliant.
Rokeberg	014	will accept compliments
Davies	016	~~communal~~ issues as well as state
Dyson	021	local case work
Davies	023	PS 15
Rokeberg	024	Amendment 8, discusses. (pauses) continues w/ Amendment
Davies	049	Source of my discomfort, NPUC does have regulatory authority. No constitutional issues. Leg. change statutes, not required. Delete all.
Rokeberg	064	Okay, will re-write, split in the committee, need to be clear
Davies	070	move ahead, universal service, need to be statutory change
Rokeberg	078	will make another attempt
Hudson	079	Will drop off, I see you on the 18th
S. Lemmon	083	before you drop off, should we meet at 10 am instead of 10:30 am
Dyson ^{Hudson}	090	1 pm. they think meeting will be
Davies	102	One more comment before we close.
Rokeberg	108	Doesn't understand
Davies	110	clauses.
Rokeberg	115	Review minutes
Davies/Rokeberg	116	Both are talking.
Davies	121	APUC brings up guidance.
Roke/Davies	127	Both discuss
Davies	129	Pilot program brings up concerns
S. Lemmon	140	Pilot will be restricted to Anchorage Market. Doesn't feel inappropriate (restricted)

SPEAKER	TAPE #	SIGNIFICANT INFORMATION
S-Leman	157	Brings up March 1st, weeks or months after.
Robebers	154	RFP, timeframe. R. Davies/Robebers back forth.
Leman	167	Aggressive schedule, reasonable way to split work, consultant agrees.
Davies	172	Broad legislative policies. Answer we have.
Robebers/Davies	184	Both talking, going back & forth, finishes, that's it.
Davies	197	48 contiguous states, brings up Hawaii; will suggest comments I get today. Pg 18 2nd Recomm.
Leman	198	Leg. will respond, should be APUC.
Robebers	219	Doesn't agree.
Leman	222	Sponsor of legislation, not speaking against.
Robebers	228	both are commenting on leg. & what each means. S Leman will get recomms to Robebers. Robebers makes
Leman	229	might agree w/ this
S Leman	242	Statue needs to be looked into
Robebers	249	Review language #2. more context
Davies	252	Agrees w/ S Leman's drift. Statutory authority.
(P) Robebers	270	Needs consensus
(S) Leman	272	gives possible language, will offer wording. Will give it some thought
Robebers	283	Doesn't necessarily disagree. How what from policy guidelines.

SPEAKER	TAPE #	SIGNIFICANT INFORMATION
S. Jemman	297	^{write} Committee to recommend R. 1st study in Anchorage. Enough said
Rokeberg	310	Supports. Looks forward to comment
Dyson	312	2 suggestions PS 12 Consumer protection move 2nd to 1st. gives language "Protected monopoly" protect consumers from monopoly of utility companies.
Rokeberg	356	Thank you, pls. clarify
Dyson	359	will write out for comm.
Davies	364	Little bit of problem w/ editorial comments. Bring up APUC.
Dyson	393	Accepts that clarifies comments. APUC sits & waits, not pro-active
DYSON	429	PS 15 2nd paragraph, not what said, ~~but~~ but how said. Adds comments
Rokeberg	446	objections, no we will adapt,
Rokeberg	450	Wants to go over recommendations.
		No objections to Amend 1, Amend 2,
S. Jemman	466	Amend 3 - has one or 2 pgs to add on this comments.
Rokeberg	475	explains Amend 3. Amend 4 no objection
11	502	Amend 5 no objection, ~~no objection~~
11	523	Amend 6, objections too.
Davies	537	Central one universal driver of power
		Rokeberg Davies discuss & speak forth
Bob Zahr	575	Clarifies, below certain temp cannot shut off power.
Rokeberg	588	Policy?
Zahr	592	Policy. Was being hard? 2d resp.
Rokeberg	600	Not a part of law

SPEAKER	TAPE #	SIGNIFICANT INFORMATION
Bob Johns	601	tanff - clarified
Ornquist	000/2A	Starts to defend Johns's statement
		tape malfunction, change tape.
(R) Robekus	new tape 001/2A	Disagrees with this brings up policy.
Ornquist	013	Brings up debate, policy vs. regulation.
(R) Robekus	024	Sorry
(R) Davies	025	Appreciates discussion, basic concepts / universal service.
Ornquist	030	Explains Universal Service.
Robekus/Davies	034	Low income assistance.
Davies	038	Universal Service, available to everyone.
Robekus	041	Subsidies, universal service, conservation programs
Davies	049	line 3 Amend.
Robekus	055	Will strike Amend. 6
Dyson	056	Public policy, decision, power available.
Robekus	064	Why I offered it.
Davies	065	Subsidy involved, universal service means everyone gets it
Dyson	080	Agrees
Robekus	083	il withdrew Amendment.
Robekus	084	Amend. 7 no objections
Robekus	090	Amend 9, Amend 10 no objections line 1, paragraph #
Robekus	103	S. Leman Call to comment?
Robekus	105	Adopted, no objections
Leman	110	offers amendment, (PS 18)
Robekus	115	Leaning, S. Leman yes

JOINT COMMITTEE ON ELECTRIC UTILITY RESTRUCTURING
JANUARY 18, 1999
10:00 am

TAPES
1-A

CALL TO ORDER

CO-CHAIRMAN ROKEBERG convened the Joint Committee on Electric Utility Restructuring at 10:07 am.

PRESENT

Committee members present were Co-Chair Rokeberg, Senator Leman, Representative Dyson, Representative Davies, Representative Austerman.

ABSENT

Senator Adams, Senator Taylor, Co-Chair Sharp.

ALSO ATTENDING

Representative Hudson, Mary Ann Pease, Aurora Power; Meera Kohler, ML&P; Eric Yould, ARECA.

SUMMARY OF INFORMATION

CO-CHAIR ROKEBERG: Calls the committee meeting to order, calls roll and welcomes all members and guests. Have a quorum to conduct business. Goes over agenda, final report of the committee to the 21st Legislature. Introductory remarks, states this report is the next step in consideration of Electric Utility Restructuring and whether it is applicable to Alaska. Thanks all committee members and others who assisted in the making of this report for all the hard work and participation. Brings up the good work between the committee and the APUC and their assistance to the committee. Asks committee members if they have any comments. Again, states this is a draft, members' comments are on the back of the report, any revisions or additions, the Chairman asks the members to do so. After reviewing the report any changes, or causes for "heartburn" let the Chairman know. Thanks his staff members Janet Seitz for heading up this effort, and Dianna Pree for her assistance to the committee. Will put together an entire record of the committee and will forward to the archives, also will be providing the contractors with a copy of the entire committee record.....

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SENATOR LEMAN: CH2MHill & Econergy.

CO-CHAIR ROKEBERG: Will give CH2MHill & Econergy a copy of the entire committee record and will keep an entire record in Chairman's office. Will forward a copy to the 21st Legislature a copy of the entire committee record. Any comments or questions? Deadline for comments is the end of the day. Opens to the committee any comments.

REPRESENTATIVE DYSON: Joint Committee findings and conclusions, page 22, end of first paragraph. Doesn't remember having technical problems with incompatible frequencies in this state.

CO-CHAIR ROKEBERG: This was submitted as written testimony. Ms. Kohler.

MEERA KOHLER, ML&P: (indisc.) system is at 50, frequency of (indisc.) contiguous connected....

REPRESENTATIVE DYSON: Asks if we have any contiguous connections with BC or Yukon.

MEERA KOHLER: If there were to be interconnections, that is where it would be.

CO-CHAIR ROKEBERG: Asks Representative Dyson if he wants this taken out of the report.

REPRESENTATIVE DYSON: States add phrase "if interconnections are made with (indisc.) Canada."

CO-CHAIR ROKEBERG: Any objections? No objections.

REPRESENTATIVE DYSON: Last paragraph, page 23, end of the first sentence. "If this pilot program can be designed in a meaningful manner". Asks for clarification, all-inclusive?

CO-CHAIR ROKEBERG: Clarifies this. States it was his word "meaningful". Any suggestions? Point was to make it a meaningful study.

REPRESENTATIVE DYSON: Concern is that it has very limited use, as it is only in the Anchorage market.

JOINT COMMITTEE ON ELECTRIC UTILITY RESTRUCTURING
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REPRESENTATIVE AUSTERMAN: The body of the report sets the guidelines for what the recommendations and the findings on. Page 20, talks about the pilot program and defines what you are talking about. The well meaning can be referred back to page 20, clarifies this well enough.

CO-CHAIR ROKEBERG: Any more comments?

SENATOR LEMAN: Would be happy if the report gave a positive statement regarding the pilot program; that a pilot study done in Anchorage or a limited area of the Railbelt, is desirable and should be designed properly. Hopes that the final result/report of the committee is a very positive statement in regards to the pilot program.

REPRESENTATIVE AUSTERMAN: Page 20 gives this positive statement.

CO-CHAIR ROKEBERG: Language in the recommendations gives this.

SENATOR LEMAN: Doesn't object too, could be crafted a little differently, in the interest of reaching consensus with this group is willing to accept this.

CO-CHAIR ROKEBERG: Any further comments on this issue?

SENATOR LEMAN: A few little things, relatively minor, mentioned in the last meeting, dates have not passed regarding a selection and the notice to proceed for the consultant with no objection from the body. Pick up the actual dates, make the report read so it is current as of tomorrow when it is delivered to the Legislature, consultant is under contract and is proceeding right now.

CO-CHAIR ROKEBERG: No objection.

SENATOR LEMAN: Has a few editorial comments that he won't bring up now, as these comments will not change the body of the report.

REPRESENTATIVE DAVIES: Has a few typo kind of things that he will submit as marginal comments. Page 18 statutory guidance & page 19 APUC, significant amount of redundancy, especially under APUC, bottom of page 19 and first paragraph on page 19, a^lmost identical wording. Get rid of the whole sub-section on the bottom of page 19 and add it to the statutory section and substitute the bottom paragraph for the first paragraph on page 19.

JOINT COMMITTEE ON ELECTRIC UTILITY RESTRUCTURING
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CO-CHAIR ROKEBERG: He believes there is a difference there, whether it is the APUC paragraph on the bottom of 19, takes this as an expression of preference on the part of the commission as articulated by the APUC, whereas, the guidance issue is the discussion that was held within the committee.

REPRESENTATIVE DAVIES: He believes slightly different perspective, same issue. Looking at the wording, these two paragraphs almost identical wording.

CO-CHAIR ROKEBERG: Calls a brief at ease at 10:21 am. Calls meeting back to order at 10:23 am. Asks if Representative Davies would like to recommend an amendment.

REPRESENTATIVE DAVIES: Moves a conceptual amendment on the bottom of page 18, that the headline would be statutory guidance to the APUC. The paragraph that exists at the bottom of page 19, would be incorporated into the first paragraph on page 19.

CO-CHAIR ROKEBERG: "Could we delete that?"

REPRESENTATIVE DAVIES: "You could, but you might want to use some of the wording, merge those to essentially."

CO-CHAIR ROKEBERG: Any objections? Hearing none so ordered. Further discussion.

SENATOR LEMAN: Moves that the committee adopts this as the report of the committee.

CO-CHAIR ROKEBERG: Appreciates that, any objections to taking up discussion on this adoption.

REPRESENTATIVE AUSTERMAN: Seconds the motion made by Senator Leman.

JOINT COMMITTEE ON ELECTRIC UTILITY RESTRUCTURING
JANUARY 18, 1999
10:25 a.m.

REPRESENTATIVE DAVIES: Agrees with the understanding that the Chairman will accept drafts for some minor wording changes, concurs with the motion.

CO-CHAIR ROKEBERG: Further discussion? Seeing none, so ordered. Meeting adjourned at 10:25 am.

Adjournment

The meeting was recorded and handwritten log notes were taken. A copy of the tapes and log notes may be obtained by contacting the House Records Office at 130 Seward Street, Suite 211, Juneau, Alaska 99801-1182, and after adjournment of the second session of the Twentieth Alaska State Legislature in the Legislative Reference Library.



EUR

DATE: 1/18/99

SIGN - IN

Funeral Report

NAME

ADDRESS

(MAILING) & (ZIP)

PHONE

REPRESENTING

**DO YOU WANT
TO TESTIFY?**

[illegible]

COMMITTEE TAPE LOG

COMMITTEE:

EUR

DATE:

1/18/99

TIME:

10:07am

SUBJECT:

Annual Report Joint Committee

MEMBERS:

Present: Rep(s) Austerman Co-Chair Rokeberg, ^{Rep} Dyson, Sen(s) Leman
Rep(s) Daines (Rep Hudson) Absent: Sen Adams, Sen Starn
Sen Taylor

SPEAKER	TAPE #	SIGNIFICANT INFORMATION
Rokeberg	001A	welcomes members, calls roll, goes over agenda. Thanks "all" for participating. Invites comments, revisions.
		- CH2M Hill, Economy - will get entire copy of committee record.
Rokeberg	082	Asks for comments, begins to go over
Rep Dyson	090	PS 22, end of 1st paragraph.
Rokeberg	099	written testimony (2) Dyson asks question
Kohler	103	Answers
Dyson	104	clarification
Kohler	105	clarifies
Rokeberg	109	States who was speaking
Dyson	111	Changes
Rokeberg	113	no objections
Dyson	115	PS 23, pilot program
Rokeberg	128	Answers
Dyson	136	Anchorage market.
Austerman	142	Brings up body of report. PS 20 defines
(S) Leman	149	pilot program, Positive statement
Austerman	161	Comments.
Rokeberg	163	
Leman	164	consensus
Rokeberg	167	
Dyson	168	NO
Leman	170	minor pts, Dates, current tomorrow - consultant has been selected.

SPEAKER	TAPE #	SIGNIFICANT INFORMATION
Roberts	178	no objections
Loman	180	minor pts worth bring up
Roberts	183	Recognize Rep. Hudson
Davis	187	minor pts, typogr p 8/9. Redundancy
Roberts	202	APUC, guidance issue
Davis	208	Redundancy
Roberts	211	calls brief at ease 10:21 am
11	211	calls meeting back to order at 10:23 am
Davis	215	Amendment pg 18, pg 19
	220	objections
Roberts	223	none so ordered
Loman	225	Adopt this as report today
Roberts	227	objections
Roberts	229	None, so ordered
Roberts	232	2nd
Roberts	242	so adopted, adjourned meeting at 10:25 am

SCOMM

109:2

FILE CONTENTS PAGE:

August 6, 1998 Agenda
August 6, 1998 Committee Packet
July 30, 1998 Additional items for Committee Packet
August 5, 1998 letter from Gail Chambers, Weidner Investment Services
August 3, 1998 letter from Max Lowe, Regal Alaskan Hotel
August 6, 1998, "Alaska Electric Utility Restructuring", Donn T. Wonnell, Counsel
For Municipal Light & Power
August 6, 1998, Aurora Power Presentation
Aurora Power Resources' Application to APUC to Establish a Pilot Program
August 6, 1998, testimony of Robert A. Wilkinson, Copper Valley Electric
August 6, 1998, "Electric Industry Restructuring", ARECA Report
August 6, 1998, testimony of Bruce Scott, Matanuska Electric Association
Written statement of Mike Kelly, Golden Valley Electric, dated July 1998
August 6, 1998, testimony of Eugene Bjornstad, Chugach Electric Association
July 29, 1998 news article, "Utilities Lick Wounds After Encounter
With Sharp-Toothed Power Traders"
July 16, 1998 DRAFT, Solicitation and Request for Proposals
July 10, 1998 news article, "Deregulation puts electricity reliability in question"
August 7, 1998, "Basic Perspectives on the Electric Power Industry", Municipal
Light & Power

ALASKA STATE LEGISLATURE

Joint Committee on Electric Utility Restructuring

Senate Members:

Sentor Bert Sharp, Co-Chairman

Senator Loren Leman

Senator Robin Taylor

Senator Al Adams

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Rep. Alan Austerman

Rep. Fred Dyson

Rep. John Davies

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AGENDA

August 6, 1998

- 10:00 a.m. Opening Remarks from Co-Chairmen
- 10:15 a.m. CEA (Eugene Bjornstad, General Manager)
- 10:40 a.m. ARECA (Eric Yould, Executive Director)
- 11:05 a.m. APUC ➤
- 11:30 a.m. ML&P (Meera Kohler, General Manager)
- 11:55 a.m. - 1:15 p.m. - Lunch break
- 1:15 p.m. Announcements
- 1:30 p.m. MEA (Wayne Carmony, General Manager, or Bruce Scott, Consumer Relations)
- 1:55 p.m. GVEA (Mike Kelly, President & CEO)
- 2:20 p.m. Aurora Power (Mary Ann Pease, Vice President)
- 2:45 p.m. IBEW (Gary Brooks, Business Manager, or Ann Hayes) ↑
- 3:05 p.m. 4-Dam Pool (Robert Wilkinson) ↗
- 3:15 p.m. - 3:30 p.m. - Afternoon break (coffee and snacks at Glacier Brewhouse)
- 3:35 p.m. Committee Discussion
- 5:00 p.m. Adjourn

➤ = no written testimony submitted

ALASKA STATE LEGISLATURE

Joint Committee on Electric Utility Restructuring

Senate Members:

Sentor Bert Sharp, Co-Chairman

Senator Loren Leman

Senator Robin Taylor

Senator Al Adams

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COMMITTEE PACKET FOR AUGUST 6, 1998 MEETING

1. Copy of enabling resolution
2. April 30, 1997 AG opinion (NOTE: **If you read nothing else, please read this. Rep. Rokeberg**)
3. October 10, 1997 ARECA letter to Rep. Rokeberg
4. Articles from July 1998 **Governing**:
 - a. "Power Politics"
 - b. "An Electrifying Breakthrough"
5. "Power Business" from September 29, 1997 **Fortune** magazine
6. Information from Patricia M. DeMarco at Anchorage Economic Development Corporation:
"Transition Cost Issues for US Electricity Utilities"
7. Columbia Steel Case (111 F.3d 1427)
8. APUC Order, Docket U-97-201, Order #3
9. NCSL information
 - a. "Standing the Electricity Industry on Its Head", **State Legislatures**, March 1997, with accompanying fax memorandum updating it.
 - b. Glossary of Terms from NCSL Web Site.

DEPARTMENT OF LAW**OFFICE OF THE ATTORNEY GENERAL**

April 30, 1997

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The Honorable Norman Rokeberg
Alaska State Legislature
State Capitol
Juneau, AK 99801-1182

The Honorable Jerry Sanders
Alaska State Legislature
State Capitol
Juneau, AK 99801-1182

Re: APUC Authority

Dear Representatives Rokeberg and Sanders:

At the House Labor and Commerce Committee hearing on HB 235 on April 16, 1997, you asked Robert A. Lohr, Executive Director of the APUC for a report on the Commission's authority to issue an electric utility a certificate to compete with an existing utility, and to impose conditions that protect the public from "cream-skimming." Because these questions involve a review of legal authorities, the Attorney General's Office, as legal counsel for the Commission, was asked to prepare this response.

The APUC Has Authority Under Current Law to Issue Certificates Allowing Competition in Electric Utility Service.

A. *Statutory Certification Authority*

The Alaska legislature has required a public utility to obtain a certificate of public convenience and necessity from the Alaska Public Utilities Commission before operating or receiving compensation for providing the utility commodity or service. AS 42.05.221(a).¹ Through this statute, the

¹ SECTION 42.05.221. CERTIFICATES REQUIRED. (a) A public utility may not operate and receive compensation for providing a commodity or service without first having obtained from the commission under this chapter a certificate declaring that public convenience and necessity require or will

4:05 p.m.
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legislature placed control over entry into the utility business in the Commission's hands. Nothing in this statute suggests that the certificates granted by the Commission are exclusive, or that the Commission's authority to grant a certificate is restricted or limited if the applicant would compete with an existing utility.

AS 42.05.241 establishes procedural and substantive guidelines for the Commission in exercising its authority to grant certificates. This statute provides:

A certificate may not be issued unless the commission finds that the applicant is fit, willing and able to provide the utility services applied for and that the services are required for the convenience and necessity of the public (emphasis added)

In compliance with this statute, the Commission must examine the question of whether the public needs the additional service when it considers granting a competing certificate. The Commission cannot grant the competing certificate unless, after examining the question, it finds that the public convenience and necessity do require the competing service.

The term "public convenience and necessity" cannot support an argument that competing certificates are prohibited. Interpreting this term, one court looked back to previous decisions and said:

The court has stated that the "public convenience and necessity" standard allows the department to exercise wide discretion to take into account a broad range of factors in making the determination whether it has been met. Almeida Bus Lines, Inc. v. Department of Pub. Utils., 203 N.E. 2d 556 (1965). Holvoke St. Ry. v. Department of Pub. Utils., 198 N.E. 2d 413 (1964). Newton v. Department of Pub. Utils., 160 N.E.2d 108 (1959) (all of which discussed the propriety of using the value of competition as a basis for making a "public convenience and necessity" finding).

Zachs v. Department of Public Utilities, 547 N. E. 2d 28 at 32 (Mass. 1989). (State reporter citations omitted).

Therefore, although it requires the question to be addressed and a finding made, AS 42.05.241 gives the Commission the policy-making authority to grant a competing certificate, including

require the service. Where a public utility provides more than one type of utility service, a separate certificate of convenience and necessity is required for each type. A certificate must describe the nature and extent of the authority granted in it, including, as appropriate for the services involved, a description of the authorized area and scope of operations of the public utility. . . . (emphasis added)

The Honorable Norman Rokeberg

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a competing electric utility certificate, if the Commission decides that the public will benefit from competing utility service.

B. Natural Monopoly Theory

It is true that in the past the Commission has not issued certificates authorizing competitive provision of electrical service. This long-standing policy is not based on lack of authority or on any legal restriction prohibiting the Commission from issuing a competitive utility certificate. The non-competitive policy is based on an economic theory widely accepted in the past, but now subject to question (or already rejected) in policy debates all over the United States and in some foreign countries as well. The economic theory was that utilities, including electric utilities, are natural monopolies and should have exclusive service territories because competition would mean wasteful duplication of the capital investment in facilities required to provide the service.

As discussed above, the natural monopoly theory is not formalized in Alaska's statutory scheme, and therefore no statutory change is required before the Commission can consider whether the public convenience and necessity require any competing certificate to be issued. The Commission has authority to change its monopoly policy in granting certificates.

The natural monopoly theory is also not formalized in the legal concept of a certificate. In Alaska, a series of court decisions resulted from competition between electrical utilities in the 1960's and 1970's. These cases involved competition between REA cooperative electric utilities certificated by the Commission, and municipally owned utilities operating under statutory authority. Before 1970, the municipal utilities were not required to obtain certificates from the Commission.

In the first of these cases, the Alaska Supreme Court rejected the argument that a certificate granted by the Commission was an exclusive right to provide service in the specified service area. It is arguable that this ruling only addressed the situation of competition from an uncertificated utility operating under a municipality's statutory authority. Nevertheless, it is clear that the court rejected the argument that the natural monopoly theory must lead to the conclusion that a certificate is an exclusive right to serve a particular area. Homer Electric Association v. City of Kenai, 423 P.2d 285 at 288-289, n. 16. (1967). See also, Chugach Electric Association v. City of Anchorage, 426 P. 2d 1001, 1003 (1967).

In these decisions, the court recognized that the effect of holding that a utility certificate was not exclusive could be uneconomic duplication of facilities. The court urged the legislature to fix this problem. See Homer, 423 P. 2d at 290; Chugach, 426 P.2d at 1004-05. In response the legislature adopted

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AS 42.05.221(d).² This provision, while making explicit the Commission's authority to eliminate undesirable duplication of facilities, is carefully drafted not to require the Commission to eliminate all competition. This statute directs the Commission to eliminate the competition only if the Commission finds 1) that there is competition, and 2) that the competition is not good for the public. Like AS 42.05.241, AS 42.05.221(d) clearly leaves the door open for a policy-making determination that competition between electrical utilities may be good for the public.

C. Longstanding Interpretations

Finally, the Commission has in the past interpreted its statutes to give it authority to issue competing certificates when it concluded that competition was in the public interest, and the legislature has apparently agreed. In interpreting a statute, the court will give some weight to a long-standing agency interpretation. Nat. Bank of Alaska v. State, Dept of Rev., 642 P.2d 811 at 815 (Alaska 1982). The APUC has granted competing certificates for refuse collection utilities: (Re Claude Bailey d/b/a Valley Refuse, et al, 7 APUC 97 (1985); Re Wasilla Refuse, Inc., 8 APUC 106 (1987); for radio common carriers, (RE Competition and Deregulation of Radio Common Carriers as Public Utilities, 5 APUC 86 (1982)); and for water utilities (Re Eagle Utilities, Inc., 7 APUC 548 (1986). For telecommunications utilities, statutory directives (state and federal) now require the Commission to grant competing certificates. In adopting a mandate for competition in long distance telephone service (AS 42.05.800-AS 42.05.890 , § 2 ch 93 SLA 1990), the Alaska legislature did not think that the underlying statutory scheme for certification needed amendment before the Commission had authority to grant competing certificates.

² SECTION 42.05.221. CERTIFICATES REQUIRED. ...

(d) In an area where the commission determines that two or more public utilities are competing to furnish identical utility service and that this competition is not in the public interest, the commission shall take appropriate action to eliminate the competition and any undesirable duplication of facilities. This appropriate action may include, but is not limited to, ordering the competing utilities to enter into a contract that, among other things, would:

- (1) delineate the service area boundaries of each in those areas of competition;
- (2) eliminate existing duplication and paralleling to the fullest reasonable extent;
- (3) preclude future duplication and paralleling;
- (4) provide for the exchange of customers and facilities for the purposes of providing better public service and of eliminating duplication and paralleling; and
- (5) provide such other mutually equitable arrangements as would be in the public interest.

(emphasis added)

The Honorable Norman Rokeberg

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II. The Commission Has Some Authority to Prevent Cream-skimming.

When competition in utility service is permitted, it is predictable that competitors will seek to serve the most profitable customers. The competing utilities may be less willing to serve smaller users, typically residential and small commercial customers. The result may be that service deteriorates while costs rise for those customers. The practice of targeting service only to the most profitable customers is called "cream-skimming." Existing statutes, including AS 42.05.221(d),³ AS 42.05.241⁴, AS 42.05.271,⁵ and the Commission's general powers, AS 42.05.141⁶, give the Commission some authority to deal with

³ See page 4.

⁴ SECTION 42.05.241. CONDITIONS OF ISSUANCE. A certificate may not be issued unless the commission finds that the applicant is fit, willing and able to provide the utility services applied for and that the services are required for the convenience and necessity of the public. The commission may issue a certificate granting an application in whole or in part and attach to the grant of it the terms and conditions it considers necessary to protect and promote the public interest including the condition that the applicant may or shall serve an area or provide a necessary service not contemplated by the applicant. The commission may, for good cause, deny an application with or without prejudice. (emphasis added)

⁵ SECTION 42.05.271. MODIFICATION, SUSPENSION OR REVOCATION OF CERTIFICATES. Upon complaint or upon its own motion the commission, after notice and opportunity for hearing and for good cause shown, may amend, modify, suspend, or revoke a certificate, in whole or in part. Good cause for amendment, modification, suspension or revocation of a certificate includes

- (1) the requirements of public convenience and necessity;
- (2) misrepresentation of a material fact in obtaining the certificate;
- (3) unauthorized discontinuance or abandonment of all or part of a public utility's service;
- (4) wilful failure to comply with the provisions of this chapter or the regulations or orders of the commission; or
- (5) wilful failure to comply with a term, condition, or limitation of the certificate. (emphasis added)

⁶ SECTION 42.05.141. GENERAL POWERS AND DUTIES OF THE COMMISSION. (a) The Alaska Public Utilities Commission may do all things necessary or proper to carry out the purposes and exercise the powers expressly granted or reasonably implied in this chapter, including

- (1) regulate every public utility engaged or proposing to engage in such a business inside the state, except to the extent exempted by AS 42.05.711;
- (2) investigate, upon complaint or upon its own motion, the rates, classifications, rules, regulations, practices, services and facilities of a public utility and hold hearings on them;
- (3) make or require just, fair and reasonable rates, classifications, regulations, practices, services and facilities for a public utility;

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cream-skimming problems. However, because of limitations within these statutes or their general nature, the Commission's authority may not reach all variations of cream-skimming problems that may arise.

The discussion below shows how these statutes provide Commission authority to protect the public against cream-skimming, and discusses the limitations.

AS 42.05.221(d). Where the Commission finds competition exists and is not in the public interest, this statute authorizes the Commission to take action to "eliminate the competition and any undesirable duplication of facilities." This statute seems to contemplate a remedy that would eliminate the competition, not a remedy that would seek to make competition serve the public interest. For example, if an appropriate cream-skimming remedy may be to order a competitor in a concentrated market to also serve a remote community, this statute does not seem to provide that authority.

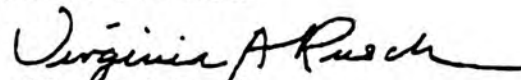
AS 42.05.241. This statute gives the Commission broad authority to impose conditions needed to protect the public when it grants a certificate. The Commission can attach to the grant of a certificate the terms and conditions it considers necessary to protect the public interest. One common remedy against cream-skimming is specifically authorized in this statute--the Commission can require a certificate applicant to provide a service that the applicant does not seek to provide. The language also clearly authorizes other remedies the Commission may devise at the time a certificate is granted. However, if the need for a condition to prevent cream-skimming does not become apparent until after the certificate is granted, this statute may not help.

AS 42.05.271. This statute is quite broad, and, along with the Commission's general powers, AS 42.05.141, arguably provides authority to address cream-skimming by requiring a utility to provide service to neglected customers. However, in the past, Commission orders have been challenged on the basis that the Commission's statutory authority is not "explicit," resulting in costly litigation over the extent of the Commission's "implied" authority.

Very truly yours,

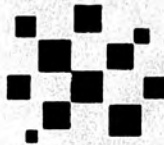
BRUCE M. BOTELHO
ATTORNEY GENERAL

By:



Virginia A. Rusch
Assistant Attorney General

VAR:jem



Anchorage Economic Development Corporation
The Center of Opportunity

July 21, 1998

Representative Norman Rokeberg
Alaska State Legislature
P.O. Box 221721
Anchorage, AK 99502-1721

RE: Electric Utility Restructing

Dear Norm:

I'm enclosing some information I thought might be of use to you. Please call if I can do anything to assist you with the process.

Sincerely,

Patricia M. DeMarco, Ph. D.
President

Enclosures

TRANSITION-COST ISSUES FOR US ELECTRICITY UTILITIES¹

Eric Hirst, Lester Baxter, and Stan Hadley

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KEY WORDS: electricity, regulation, competition, finances, economics

ABSTRACT

The US electric-utility industry is in the midst of major changes. These changes include deintegration of the industry and substantial increases in competition. A major consequence of these changes is the exposure of transition costs. These costs, which amount to \$100–\$200 billion nationwide, reflect the differences between regulated prices for electricity generation and the prices that might occur in fully competitive power markets. The large financial stakes, equivalent to nearly the total value of US electric-utility common stock, guarantee controversy. Debates occur over transition-cost amounts; analytical and market methods to estimate these costs; the assets and liabilities to include in such calculations; the assumptions used in developing these estimates; approaches that can be used to offset some of these costs; the allocation of the remaining costs among utility shareholders, different classes of retail customers, independent power producers and other wholesale suppliers, and taxpayers; and appropriate cost-recovery mechanisms.

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1. BACKGROUND

Transition costs (TCs) are the potential monetary losses that electric-utility shareholders or other parties might experience because of structural changes in the electricity industry. These are not new costs, but rather sunk costs and future obligations that may not be recoverable in competitive electricity markets. In rough terms, transition costs are based on the difference between regulated retail electricity prices for generation services and the competitive-market price of power. The retail-monopoly franchise that investor-owned utilities enjoy today permits them, with approval from their state regulatory commission, to charge customers for all the costs of producing and delivering electricity. In a competitive electricity market, the frequent interaction of buyers and sellers, rather than regulators, will set prices. If these prices are below embedded costs, then transition costs will occur.

Transition costs are a much more serious problem in the United States than in other countries that have restructured their electricity industry. Unlike other countries in which governments own most of the electric-system facilities, private companies account for the vast majority (about 75%) of US electricity production, investment, sales, and revenues; government- and consumer-owned utilities account for the remaining one fourth. Also, the boundaries between state and federal jurisdiction complicate treatment of TCs in the United States.

Consider a simple example of transition costs. The total costs of generation include capital (depreciation, interest payment on bonds, return on common equity, and taxes); fuel; and operations and maintenance (O&M). Traditionally, these costs are reviewed by state regulatory commissions. If approved, these costs are then incorporated into the rates that the utility is allowed to charge its customers. In this example, the utility has capital costs that are equivalent to 2.1 cents per kWh, fuel costs of 1.6 cents per kWh, and O&M costs of 0.7 cents

per kWh, leading to a total embedded cost of generation of 4.4 cents per kWh. By comparison, the market price of power in this case is only 2.5 cents per kWh. These numbers suggest that the utility would lose the equivalent of 1.9 cents per kWh if it sold electricity to its retail customers at competitive market prices.

Failure to fully and fairly consider such costs could be a major impediment to industry restructuring. Studness (1) argues that "Recovery of stranded investment is clearly the central point of contention in the debate over utility competition.... Utilities argue that the 'regulatory compact' entitles them to full recovery; customers claim that no such entitlement exists." The Federal Energy Regulatory Commission (FERC) in its final rule on open-access, nondiscriminatory transmission service, devoted 187 pages of its 780-page order to TCs (2). FERC noted that "the recovery of legitimate, prudent and verifiable stranded costs is critical to the successful transition of the electric industry to a competitive, open access environment."

Transition costs can include four classes of costs:

1. assets, primarily in expensive power plants and excess generating capacity;
2. liabilities, primarily in power-purchase contracts, fuel-supply contracts, and deferred income taxes;
3. regulatory assets (whose value is based on regulatory decisions rather than on market forces), including deferred expenses for power plants and costs for demand-side management programs that regulators allow utilities to place on their balance sheets; and
4. public-policy programs, including tax collection, environmental compliance beyond that required by law, demand-side management programs paid for by all customers, special programs for low-income customers, and support for energy research and development. Unlike the other three categories, the costs in this category are current, not sunk.

Several entities have estimated the TC amounts that individual utilities might face. For example, Moody's Investors Service (3) analyzed data for 116 utilities (representing more than 80% of the assets of all US investor-owned utilities). They estimated that TCs could amount to \$133 billion, almost 90% of shareholder equity. (All monetary values are in 1994 dollars.) All told, 34 of the 116 utilities included in Moody's analysis had potential transition costs in excess of their equity (Figure 1). Oak Ridge National Laboratory (4) developed national after-tax estimates for investor-owned utilities that ranged from \$16 billion to \$268 billion, and suggested that the most plausible range is \$72-\$104 billion. Prudential developed a TC estimate of about \$30 billion (5).

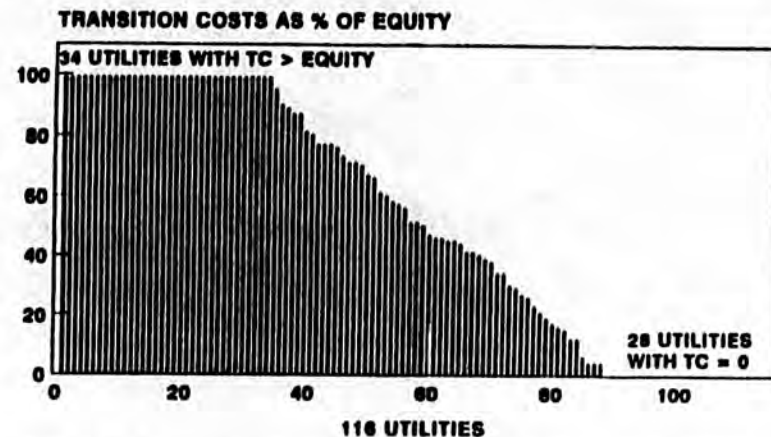


Figure 1 Moody's estimates of transition costs relative to shareholder equity for 116 US investor-owned electric utilities.

Resource Data International (RDI) estimated a nationwide TC of \$184 billion (6). Of this total, \$134 billion is accounted for by investor-owned utilities, \$29 billion by municipal utilities, and \$20 billion by cooperatives. (Most of the other estimates we reviewed dealt only with investor-owned utilities.) Utility-owned generating units account for the largest share of the \$184 billion, \$65 billion. RDI calculates the nationwide TC for nuclear units at almost \$79 billion, offset by a negative TC for fossil and hydro units of \$15 billion. Regulatory assets account for \$45 billion of TC, power-purchase contracts with nonutility generators for \$38 billion, power-purchase contracts with other utilities for \$49 billion, and sales contracts for a negative \$11 billion. California, New York, and Texas together account for more than 40% of US transition costs, according to this analysis.

RDI also identified several utilities that had below-market costs, leading to a total negative TC of \$54 billion. In general, these utilities had little exposure to nuclear plants and had many other generators with embedded costs below market prices. These utilities also had few regulatory assets and had large potential gains from their power-sales contracts. States with zero or negative TCs include Utah, Tennessee, Oregon, Oklahoma, Washington, Minnesota, Kentucky, Wisconsin, Iowa, and Montana.

The estimates, which were developed by different entities, at different times, with different metrics and assumptions, vary. For example, the estimate by Prudential Securities is considerably lower than the other national estimates cited above. This difference is at least partially caused by Prudential's inclusion of fewer utilities in its analysis, its assumption that only future revenues from

commercial and industrial customers are at risk, and its use of a higher market price for electricity that includes capacity. Studies that use similar assumptions, even though their specific estimation approaches differ, often yield more similar results. The correlation coefficient (r) between estimates of utility transition costs from Oak Ridge National Laboratory and from Moody's study is 0.84, for example, for the 111 companies in both analyses.

Our review of these estimates of transition costs leads to several conclusions. First, although the methods used and results obtained differ across these analyses, they generally suggest that the potential losses associated with TCs are substantial. Second, they show that the losses are unevenly spread among both utilities and regions. Third, the range of recent estimates of the nationwide losses is much smaller than the range estimated a few years ago; this reduction in range is a consequence, we believe, of growing agreement on what assets and liabilities should be considered in calculating TCs. Fourth, despite the narrowing of recent national estimates, the results obtained, even for the same situation, can differ substantially depending on the perspective of the entity making the estimates, the analytical approach used, and the assumptions made. Figure 2 shows six estimates of the TCs that Central Power & Light might face (7). These estimates differ by a factor of more than three, the utility's estimate being the highest and the large industrial customers' estimate the lowest.

A full treatment of TCs would consider appropriate ways to calculate TCs; estimates of the TC amounts for individual utilities, states, regions, and the United States as a whole; strategies to mitigate these amounts; allocation of the remaining TCs among utility shareholders, different classes of customers, independent power producers, and taxpayers in general; and the mechanisms

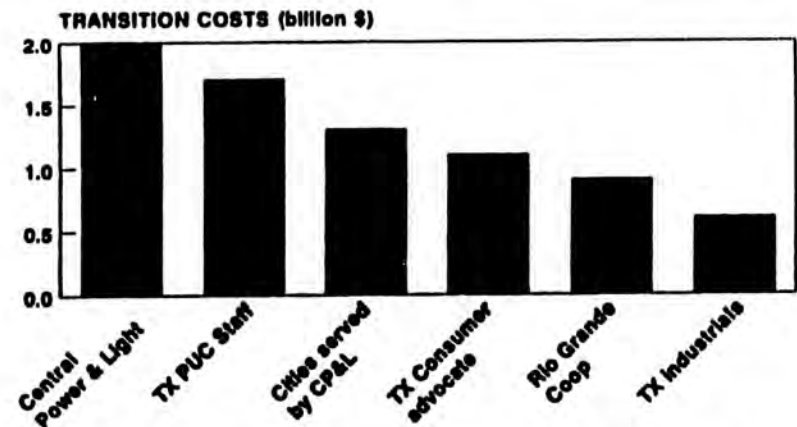


Figure 2 Alternative estimates of the transition costs faced by Central Power & Light Company.

used to allocate or recover TCs. Section 2 presents an economic framework for the definition and discussion of TCs. Section 3 discusses policy and legal issues associated with the allocation of remaining TC amounts among various stakeholders. Section 4 discusses various analytical and market-based approaches to calculating TCs. Section 5 analyzes the sensitivity of TC results to changes in input assumptions, primarily to identify the critical factors in determining TC amounts. Section 6 discusses several strategies to recover or reduce transition costs. Section 7 summarizes our key findings. See (8) for additional details.

2. THE ECONOMICS OF TRANSITION COSTS

Traditionally, state regulators have used cost-of-service methods to establish retail rates. Under cost-of-service rate making, regulators give utilities the opportunity to recover all the prudent costs the utility incurs to satisfy the demand for electricity services within its franchise area. These costs include the return of (depreciation) and return on investments in utility plant (generation, transmission, and distribution) and the ongoing costs of fuel, power-purchase, and O&M. Many of these costs are considered sunk or embedded because they have already been incurred or reflect obligations to incur future costs. (Costs that are not sunk include short-term or avoidable fuel and power-purchase costs.) In contrast, prices in a competitive market more closely reflect marginal production costs, that is, the additional costs that suppliers incur to meet current and future demand.

Transition costs are most likely to occur when utility rates are above market prices for generation services. Under these circumstances, customers will be motivated to purchase from lower-cost sources, or utilities will be motivated to reduce rates. Rose presents a simple comparative model that illustrates the implications these circumstances have for transition costs (9). Figure 3 presents a situation for a hypothetical utility and an alternative power supplier. To simplify, we remove from this example the costs for transmission, distribution, and other nongeneration costs. Under most circumstances, the utility will be able to recover these costs because it will remain the only supplier of such services (i.e. restructuring proposals continue to envision the transmission and distribution of electricity as monopoly services). These costs will probably be recovered through access fees or through regulated rates for transmission and distribution services.

The MCG_u curve in Figure 3 represents the utility's marginal cost of generation and its price for generated electricity under the new competitive regime. The figure shows the right portion of the marginal cost curve when the utility's economies of scale are exhausted. The average cost of generation (ACG_u) is also the utility's price curve under the existing embedded-cost pricing regime.

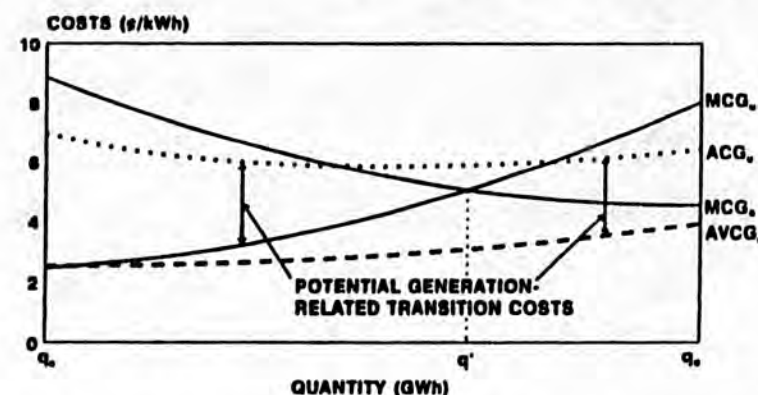


Figure 3 Comparative static model of utility transition costs. This figure is simplified to show certain features of TCs. Most importantly, the figure represents a single small increment in time, perhaps a single hour, and does not reflect the complex relationships among utility costs, prices, and market prices over longer periods. Also, the figure implies that the utility sells its generation output at marginal cost. If this was the case, the utility will also be unable to recover some or all of its average fixed generation costs when MCG_u is less than ACG_u , as depicted on the left side, unless the market price for generation is greater than ACG_u .

In this example, the utility's marginal generation costs exceed its average generation costs only at high levels of production. The utility will only recover its fixed generation costs when prices equal or exceed its average generation costs. The utility's average variable cost of generation curve ($AVCG_u$) lies below its average generation cost curve. The difference between these two curves reflects the utility's average fixed costs of generation. The final curve depicts a competitor's marginal cost of generation (MCG_a). This curve, drawn with its origin at the right axis, assumes a generally flat slope over the initial range of output and then gradually increases. This curve can also represent the market price of electricity from multiple suppliers. Finally, the horizontal axis reflects different combinations of utility and competitor power supplies that meet an incremental demand for electricity. At the right-most point (q_u), all the demand is met by the utility, while at the left-most point (q_a) all the demand is met by the competitor. Point q^* represents the optimal combination of generation supply for this level of demand, the point where utility marginal costs and supplier costs are equal.

The difference between the utility's average generation costs and its average variable generation costs to the right of q^* are unrecoverable when generation services are provided by the competitor. This area includes the utility's average fixed generation costs. These latter costs are the TCs faced by the utility, assuming that the utility does not sell this potential output in another market. The

utility does not face any other generation costs when it is no longer supplying generation. Thus, the utility does not incur the portions of average generation costs related to variable costs, such as fuel and variable O&M, when it is not generating electricity. The utility's average fixed generation costs remain however, even when a competitor is generating the electricity. Thus, Figure 3 depicts the amount of TCs when the utility previously met all demand (q_0) but now generates only the optimal quantity (q^*). In addition, the difference between the utility's average generation costs and its marginal generation costs to the left of q^* is unrecoverable when generation services are priced at the utility's marginal cost.

We make several observations about TCs based on this economic perspective:

1. The presence and amount of TCs depend on the marginal generation costs for the utility and alternative supplier and on the relationship between the utility's marginal and average generation costs.
2. TCs can occur when a competitor's marginal generation costs are below the utility's marginal generation costs or when the utility's marginal generation costs are less than its average generation costs.
3. When the competitor's marginal generation costs are less than the utility's, then the potential generation-related transition costs equal the utility's average fixed generation costs (if the utility does not sell this electricity in another market).
4. When the competitor's marginal generation costs are less than the utility's, then the potential generation-related transition costs equal the utility's average generation costs minus the market price for generated electricity (if the utility does sell this electricity in another market).
5. Reductions in the utility's marginal generation costs will reduce the probability of economic bypass to competitive suppliers and, thus, of incurring transition costs, except when such reductions increase the amount that marginal costs are below average costs.
6. Properly structured competitive markets will motivate utilities to reduce generation costs and thereby reduce their TCs over time.
7. Competitive markets will define the market price for electricity (which will equal the marginal cost of electricity generation if the market is efficient) and the level of TCs.
8. As a result, transition costs are not static but will change over time, depending on changes in the competitive market price for electricity and the utility's generation costs.

One additional complication that some utilities face is that not all generation costs are included in today's average cost of generation. Today's average costs reflect sunk costs and historical obligations that extend into the future. Two important historical obligations, long-term power-purchase contracts and fuel-supply contracts, are included in today's average costs. Two other future costs may not be fully included and are not avoidable by utilities or society at large. These are the costs associated with the decommissioning of nuclear power plants and the environmental mitigation or restoration costs associated with past utility actions. Because these two classes of costs are largely unknowable today, it is not possible to accurately include them in today's TC estimates.

3. TRANSITION-COST ALLOCATION

Perhaps the most important, and difficult, TC issue facing regulators is deciding how to allocate nonmitigable transition costs among the various parties. Not surprisingly, debates on this issue at the state and federal level have been quite heated. In part, this controversy is a consequence of the large dollar amounts at stake. The controversy may also result from the fact that this issue has to be decided primarily on the basis of policy rather than science. In other words, science has little to contribute to legislative and regulatory decisions concerning the allocation of these costs. Opinions differ strongly on whether utilities are entitled to full recovery of their TCs. Large industrial customers, consumer advocates, and some regulators argue that there is no constitutional entitlement to the recovery of such costs; indeed, these costs should be subject to the same types of prudence and used-and-useful criteria that commissions have long applied to utility actions. On the other hand, many utilities argue that the Takings Clause of the US Constitution (Fifth Amendment) requires full compensation for such costs; they suggest that these costs were incurred with the approval of regulators.

3.1 *Pro-Recovery Arguments*

The primary proponents of the argument that utilities are entitled to and should receive full recovery of their transition costs are, not surprisingly, the investor-owned utilities themselves. Baumol, Joskow, & Kahn offer arguments, based on economics and regulatory policy, supporting shareholder recovery of TCs (10). They suggest that increasing economic efficiency should be the primary objective of restructuring the electricity industry. They argue that, when properly structured, competitive markets are more likely to increase economic efficiency than are regulated markets. These efficiency gains will involve both productive efficiency (i.e. providing goods at minimum cost) and allocative efficiency (setting prices correctly, based on marginal costs). The authors argue

that unless TCs are properly addressed, the efficiency gains from competition may be eroded. The authors' primary conclusion is that equity and productive efficiency considerations support a policy of full TC recovery for utility shareholders. On the equity side, the authors believe that shareholders have not previously received compensation from their allowed equity returns for the risk they now face of not being able to recover their investments because of changes in government policy. Further, they note that utilities incurred most of these costs with the full approval, and sometimes at the mandate, of regulators. Should shareholders fail to recover TCs, the efficiency consequences include distortion of competition between utilities and alternative suppliers, extension of the time to competition, and the possibility of increased capital costs to the electricity industry. The authors indicate that TC recovery can be compatible with efficient competition when the recovery mechanism is properly structured. To ensure that competition between rival suppliers is based on efficiency, the authors recommend that the costs of historical obligations be assessed from all customers who have benefited from those obligations.

Rowe & Graening develop legal arguments to justify full payment to utility shareholders of TCs (11). On the basis of the Takings Clause, they argue that the government may require private property owners to cede rights to that property to serve the public good, but it must then ensure just compensation to the owner. Paying transmission owners the embedded costs of their transmission system is irrelevant, in part because transmission is an integral part of a utility's larger generation, transmission, and distribution system. Allowing others to use a utility's transmission system adversely affects the value of a utility's generation assets, and for this reduction in value the utility is entitled to full compensation. Rowe & Graening write:

The integration of distribution, transmission and generation into a tightly woven commodity delivery system performs as a whole. One part severed from the others can drastically reduce the property's comprehensive value. If the wires are severed from the generation, their loss will destabilize the value of the overall property. The result would be akin to a tricycle with only two wheels broken and going nowhere.

Kolbe & Tye argue that the rates of return historically allowed by state public utility commissions (PUCs) were insufficient to compensate shareholders for the risk associated with retail competition (12). For utility shareholders to have been automatically compensated by regulators for the risk of TCs, the allowed rate of return would have had to have been much higher than the actual cost of capital. Further, the increment above the cost of capital is very case specific (i.e. it depends on the particular situation facing that utility). Kolbe & Tye believe it is unlikely that PUCs were performing the necessary company-specific calculations to determine the authorized ROE.

3.2 Anti-Recovery Arguments

Large industrial customers and low-cost utilities, among others, oppose payment of full transition costs to utilities (13). They argue that payment of TCs to utilities will have anticompetitive and uneconomical consequences by providing payments to high-cost producers that will discriminate against low-cost producers. Full-cost recovery also ignores any utility responsibility for these costs and their consequent obligation to pay for at least some of them. Navarro believes that allowing full recovery of TCs is unfair to consumers, would provide a shield for high-cost producers and discriminate against low-cost producers, and would reward utilities for past "bad management decisions" (14).

Rose argues that TC recovery by utility shareholders is not supported on grounds of either economic efficiency or historical regulatory policy. He states that the concept of transition costs, and arguments for its recovery by utility shareholders, has little basis in economic theory, legal precedence, or precedence in other deregulated industries.

Rose first considers the argument that TC recovery is required for economic efficiency. This argument is based on a narrow definition of efficiency preventing uneconomical bypass of the utility's system (i.e. selecting another supplier when the utility is the lowest-cost provider for that customer). He argues instead for a broader perspective on efficiency, one that considers the long-term promotion of competitive markets and incentives for suppliers to minimize costs over time. In his view, longer-term gains from price reductions to consumers are likely to exceed the shorter-term losses from uneconomical bypass. Rose further argues that allowing TC recovery may impair the development of competitive markets by reducing utility incentives to lower costs, acting as a barrier to entry and exit of other suppliers in the marketplace, and creating an asymmetry between utility risk and reward. Finally, even if competitive forces lead to utility bankruptcies, Rose notes that society's resources will be more efficiently allocated after the financial readjustments bankruptcies will bring.

Rose next considers the argument that cost recovery is required to comply with historical regulatory policy (i.e. the "regulatory compact"). He discusses differing interpretations of this compact and concludes that full TC recovery would be inconsistent with historical regulatory policy in many states. The only entitlement granted to utilities is the revocable privilege to serve an exclusive territory, from which stems the obligation to serve. This entitlement is not an agreement to pay all prudent (and other) costs; customers have no reciprocal obligation to purchase from the utility unless a written contract is in place.

Bradford, in contrast to Kolbe & Tye, believes that utility shareholders historically have been compensated at levels high enough to cover the risks of some loss on strandable investments (15). Indeed, between 1977 and 1991, the annual

total return to shareholders for 81 utilities averaged 13.3% per year, higher than the 13.2% for unregulated industrial firms even though electric-utility stocks were less risky than the market as a whole.

3.3 Government Decisions

At the federal level, the Council of Economic Advisers favors utility recovery of transition costs (16, p. 187):

In unregulated markets the possibility of stranded costs typically does not raise an issue for public policy—it is simply one of the risks of doing business. However, there is an important difference between regulated and unregulated markets. Unregulated firms bear the risk of stranded costs but are entitled to high profits if things go unexpectedly well. In contrast, utilities have been limited to regulated rates, intended to yield no more than a fair return on their investments. If competition were unexpectedly allowed, utilities would be exposed to low returns without having had the chance to reap the full expected returns in good times, thus denying them the return promised to induce the initial investment. A strong case therefore can be made for allowing utilities to recover stranded costs where these costs arise from after-the-fact mistakes or changes in regulatory philosophy toward competition, as long as the investments were initially authorized by regulators. . . . The case for allowing recovery is even stronger where stranded costs arise from regulatory obligations imposed on utilities [such as qualifying facilities]. . . . To be sure, utilities should be granted recovery only of costs prudently incurred pursuant to legal and regulatory obligations to serve the public.

FERC, in its Order 888, clearly favors utility recovery of "legitimate, prudent, and verifiable [wholesale] costs" (2). Similarly, the California PUC (17) and the California Legislature (18) both decided to allow utilities the opportunity to recover their retail transition costs. FERC provides an extensive discussion of the many comments it received on this issue, both for and against cost recovery, and the basis for its decision to allow utilities the opportunity to recover all their TCs. FERC's decision limits utility recovery of costs to only those that can be directly attributable to FERC's Order 888 mandating open-access transmission. If, for example, a wholesale customer physically leaves a utility's service area, the utility's losses associated with this departure would not qualify for cost recovery under FERC's rule. In addition, FERC limited recovery to costs incurred prior to July 11, 1994, the date of its original stranded-cost notice of proposed rulemaking. Finally, FERC requires a utility to demonstrate that it had a "reasonable expectation" that it would continue to serve the departing wholesale customer for a certain amount of time. Thus, although FERC decided to allow utilities the opportunity to recover 100% of the costs stranded by increased transmission access, FERC clearly limited these opportunities to those that are a direct consequence of its actions.

Both FERC and California dealt with the allocation of costs among parties. With respect to the utilities themselves, both entities put in place mechanisms

to encourage utilities to cut costs (see Section 6). FERC ruled that departing wholesale customers will pay the transition costs associated with their departure. This decision ensures that neither utility shareholders nor other wholesale customers bear the costs associated with a particular customer's departure.

The California Legislature sought to ensure that residential and small commercial customers would benefit from restructuring that state's electricity industry. To that end, the legislature authorized the issuance of up to \$10 billion of government bonds, the proceeds of which would be used to guarantee residential customers a minimum 10% rate reduction and help pay for TCs. The lower interest rate on government versus utility bonds, the longer amortization period (10 vs 5 years), the exemption from state income taxes, plus the possibility of an exemption from federal income taxes will be used to provide the rate reduction to residential customers. (These securitization benefits have a cost: The state guarantees that retail electricity consumers will pay the interest and principal associated with these bonds.) The Legislature decided that all retail customers will pay for transition costs through a nonbypassable competition transition charge, allocated across rate classes in a manner similar to the cost allocation in place as of June 1996. The California legislation is important because it provides the utilities with strong assurances for recovering a substantial portion of their transition costs and it "securitizes" some of these costs in a way that reduces their magnitude. The Pennsylvania General Assembly authorized the Pennsylvania PUC to issue qualified rate orders to utilities for the issuance of transition bonds (19). As in California, these bonds would require a lower interest rate because of the state's backing (19, Section 2812, p. 73):

Notwithstanding any other provision of law, the Commission has the power to specify that all or a portion of a qualified rate order shall be irrevocable. To the extent specified, neither the order nor the intangible transition charges authorized to be imposed and collected under the order shall be subject to reduction, postponement, impairment or termination by any subsequent action of the Commission. . . . The Commonwealth will not limit, or alter or in any way impair or reduce the value of intangible transition property or intangible transition charges approved by a qualified rate order until the transition bonds and interest on the transition bonds are fully paid and discharged or the contracts are fully performed on the part of the electric utility.

Hanger, a Pennsylvania PUC Commissioner, suggests "different recovery levels for different types of stranded investments" (20). Commissions can consider the degree of utility-management responsibility for the transition costs that exist in each category. In addition, the transition costs associated with utility-owned generation assets include both a return of investment and a return on investment; commissions can consider these types of costs differently for recovery purposes. For example, commissions may allow either no return or a reduced return on equity on certain assets contributing to TCs. Alternatively,

commissions may allow only a return of capital without any return on investment. Under this policy, shareholders would forego their equity return and might also have to pay the long-term debt return to bondholders.

The New Hampshire Public Utilities Commission (21) and the Vermont Public Service Board (22) adopted TC positions more favorable to customers and less favorable to utility shareholders than did FERC or California. The New Hampshire PUC noted that, with the exception of purchases from qualifying facilities, the "New Hampshire electric utilities' historical prerogative to make resource decisions have [sic] not been significantly compromised by legislators or regulators." The Commission proposed to use New England regional electric rates as a key element in determining the amount of TCs that individual utilities could recover. That is, the utilities in the worst financial shape, as measured by their retail rates, will get the least relief in TC recovery. Specifically, the Commission stated that "it is our preliminary view that utilities with rates at or below the regional average should be provided a greater opportunity to recover net, verifiable, nonmitigable stranded costs than should utilities with rates above the regional average." The Commission reasoned that each New Hampshire utility operated under comparable economic and regulatory conditions, including participation in the same power pool, access to the same fuel markets, and the requirement to conform to the same state laws and regulations. Given these similar operating environments, one can assume that differences in utility rates are attributable primarily to utility-management decisions.

The Vermont Public Service Board is especially concerned about transition costs because rates in Vermont are increasing at the same time that they are decreasing in other New England states. The difference is primarily a consequence of the \$4 billion, 30-year contracts that the Vermont utilities signed several years ago with Hydro-Quebec. These contracts account for about 60% of the transition costs for the Vermont utilities.

The Board notes that the transition to competitive electricity markets may provide "substantial opportunities for utilities" that can be used to offset what would otherwise be TCs. The Massachusetts Department of Public Utilities (23) also notes that today's utilities have certain competitive advantages, such as "substantial physical assets including plant, equipment, and sites acquired over the monopoly period, and largely financed by ratepayers; and, in some cases, intangible assets, such as name recognition and customer loyalty." [The overall market-to-book value for the common shares of 50 large US utilities was 1.4 as of June 1996. This high valuation by utility shareholders can be interpreted as a sign of confidence that regulators will allow considerable TC recovery, that utilities stand to gain in competitive electricity markets, or both.]

The Board also plans to limit TC recovery to a five-to-ten-year transition period. It emphasizes the utilities' obligations to mitigate TC amounts and offers to provide TC recovery only after all mitigation strategies have been implemented.

The 11 mitigation strategies identified by the Board include renegotiation of power-purchase contracts; buy out or buy down of power-purchase contracts; economic operation of existing facilities and contracts; shutdown of uneconomic generating units; renegotiation of fuel-supply contracts; cost reduction; sale of uneconomic assets; write-off or write-down of uneconomic assets; appropriate load growth; exchange of underutilized assets; and refinancing of obligations through low-cost, long-term bonds (similar to the method planned for California).

The regulatory and legislative decisions in favor of cost recovery may be motivated by both philosophical and practical reasons. Philosophically, the federal and California governments recognize that many of the utility decisions that led to above-market costs (especially the purchase of electricity from qualifying facilities) were actively promoted by government. Even where decisions were not promoted by governments, governments acknowledge that the regulatory commissions approved those actions. The Vermont and New Hampshire decisions, on the other hand, favor retail customers over utility shareholders and emphasize the historical and legal responsibility of utility managements for their resource-acquisition decisions.

Practically, it might be very difficult to implement a new industry structure without the support of utilities. If utilities were informed that they would not be permitted to recover most of their TCs, they could find many ways to delay implementation of competitive markets. For example, although the Michigan Public Service Commission mandated a retail-wheeling experiment in 1994, retail wheeling has yet to begin in that state. Thus, we speculate that utilities in many jurisdictions will be allowed to recover most, but certainly not 100%, of the TCs that they cannot reasonably mitigate.

The Massachusetts Department of Public Utilities took just such a pragmatic view in its recent order (23, pp. 264-265):

In this rulemaking, we have determined that the electric companies have not established a clear legal entitlement to stranded cost recovery. At the same time, we acknowledge that the legal question of whether stranded costs are recoverable in the restructuring of the electric industry is one that PUCs and the courts have never addressed, let alone resolved. It continues to be our belief that litigation over stranded cost recovery would delay the introduction and benefits of competition for consumers. Furthermore, as a matter of sound public policy, the Department reaffirms that allowing electric companies a reasonable opportunity to recover stranded costs is in the public interest because such recovery would: 1) ensure the provision of sound electric services during the transition to competition; 2) affirm reliability of commitments, which is an essential element in any future industry structure; 3) promote federal and state coordination and ensure equal treatment of similarly situated utilities; and 4) avoid costly, reform-delaying litigation.

In deciding on how much money a utility is entitled to recover from its customers, the Department will require full documentation on such costs from each utility, including sensitivity analyses.

Some utilities have generating assets with book values below market prices. Although this situation of negative TCs has received little attention, regulators in some states will have to decide how to allocate these benefits between utility shareholders and retail customers. Presumably, the same principles that determine the allocations for positive TCs should apply to negative TCs. As noted by the staff of the Texas PUC (24), "In the transition to a competitive retail electricity market, to the extent utilities with *positive* ECOM [TCs] are granted recovery of such costs from ratepayers or otherwise, utilities with *negative* ECOM should likewise be required to pass through to ratepayers the benefits of their low cost generation resources."

Finally, having decided on the amount of TCs and the allocation of these costs among different parties, regulators must select an appropriate cost-recovery mechanism. As discussed by Baxter, Hirst, & Hadley, the mechanism chosen should promote competition and economic efficiency in bulk-power markets. In addition, the method should be administratively simple and equitable (8).

4. ESTIMATION APPROACHES

Estimation methods are important for three reasons. First, the TC estimate one obtains depends strongly on the method used to develop that estimate. (TC estimates also depend strongly on the assumptions made, as discussed below.) Second, the literature provides few details on different estimation methods. Third, regulators need simple methods for checking the reasonableness of the results their utilities present to them.

Utilities and regulators can use a variety of approaches to calculate TCs. San Diego Gas & Electric (25) developed a useful typology of estimation methods (Table 1). This framework considers three categories: administrative versus market valuation, ex ante versus ex post valuation, and top-down (TD) versus bottom-up (BU) valuation. Administrative approaches use forecasting,

Table 1 Alternative ways to compute transition costs

	Market valuation		Administrative valuation	
	Ex ante	Ex post	Ex ante	Ex post
Bottom-up	Assets sold at auction	After-the-fact purchase-price adjustment	Asset-by-asset value projections	Assets valued after restructuring
Top-down	Bundles of assets spun off	Deferred valuation of spun-off assets	Projection of regulated rate by customer class	After-the-fact adjustment of regulated prices

modeling, or other analytical techniques to estimate TC amounts. Market valuation relies on the purchase price of particular assets to determine the market value of assets, although analysis may be needed to compare market and regulated values. Ex ante approaches determine TC amounts before restructuring of the electricity industry is completed, while ex post approaches delay the valuation until restructuring has been achieved. See Baxter for an assessment of the eight approaches identified in Table 1 (26).

4.1 Market Valuation

The California Public Utilities Commission proposed that the utilities divest themselves of up to half of the fossil-fired generation they own, in part to help estimate transition costs (17). Wilson advocates the sale of assets as a preferred way to determine their true market value (27). Of course, a utility would have to sell all its generating assets, both those with above-market value and those with below-market value to determine the amount of TCs it faces (see the discussion below on administrative valuation). Nuclear and hydro units, however, pose special problems, as indicated by both the California PUC and Wilson. Lesser & Ainspan (28) note that administrative valuation requires upfront estimates of future market prices for electricity, which "will invariably be incorrect, [and therefore] the amount recovered by utilities will either be too much or too little." Use of periodic trueups also poses problems "because it requires continued definition of two key variables: the market price and the embedded price at a given time." They believe that several market prices will exist at the same time, and as evidence, note the multiplicity of prices for an airplane seat for a particular flight. (On the other hand, market- and survey-based electricity price indices exist for several locations; regulators could use these indices to define market prices.) Defining regulated costs may also be difficult given the interaction between such costs and utility cost-reduction efforts. For example, pressure from the regulator and from competitive markets may induce a utility to cut its overall heat rates, reduce its O&M costs, and take other actions that reduce its electricity-production costs.

The sale price obtained through an auction, by comparison, defines the current market price of an asset. That price will reflect the buyer's estimate of the net present value of the revenues to be generated by the asset (the product of electricity generation and the time-varying market price of power in this case) minus the ongoing costs of the asset (fuel plus O&M), plus any salvage value. An auction eliminates the need for regulators to estimate future production, book value, or market prices of electricity. All of that is left to the bidders. If the structure of the future bulk-power market is undefined at the time of the asset sales, however, the prices bid might be low because of the systemic risk of an unstable market structure.

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For example, all the generation in a region could be auctioned simultaneously over a period of several months. Potential bidders would have to demonstrate their financial viability by posting "earnest money" on all generating units on which they wanted to bid. The regulator would limit the amount of capacity that any single bidder could purchase, to prevent horizontal market-power problems. To promote an efficient auction, the current owners of these generators would be required to provide detailed information about these resources before the auction began. And potential bidders would have the right to conduct their own audits of these facilities.

When considering the specific market valuation approach to use, the potential tax implications should be assessed (29). A sale of assets, such as the divestiture of utility generating plants for cash, will be treated as a taxable event for federal and state income tax purposes. A spin-off transaction will not be considered a taxable event if the transaction comports with tax laws dealing with spin-offs. The potential tax consequences of different market valuation approaches suggest a need to consult with the Internal Revenue Service prior to implementing a specific process. Asset sales may also raise complications with mortgage bonds, many of which are backed by specific assets.

4.2 Administrative Valuation

Administrative valuation approaches use analytical techniques to estimate the market value of utility assets and obligations (30). A BU, *ex ante*, administrative approach would involve calculation of the unit-by-unit performance of each of a utility's power plants in a hypothesized competitive generation market. Some early estimates of TCs were too high because they were based on an analysis of only those generating units with book values above market values, leading to an estimate of gross TCs. An accurate assessment of such costs must include all assets, those with book values below as well as above market values, to derive an estimate of net transition costs. (A similar situation occurs with long-term obligations, such as power-purchase and -sales contracts. A power-sales contract with a price above, or a power-purchase contract with a price below, the market price of power reduces a utility's TCs.) Calculating the return provided by each generating unit involves detailed production-cost simulations for both the utility in question and the surrounding utilities and independent power producers. These simulations would show the number of hours each year that each generating unit operates, its variable production costs, the market price of power that hour, and from these numbers, the profitability of each unit. Such calculations require thousands of assumptions concerning present and future customer locations, loads, load shapes, and peak loads; transmission-system operation, expansion, constraints, costs, and pricing rules; operating costs and performance of all existing and new generating units; fuel prices;

government decisions on siting and environmental restrictions for new power plants and transmission lines; and so on. A BU analysis requires similarly detailed calculations of stranded liabilities (especially power-purchase and fuel-supply contracts), regulatory assets, and public-policy programs. The method developed by Resource Data International is probably the leading example of a BU method (6).

The TD approach, rather than using the individual asset or liability as the unit of observation, treats the utility as the unit of observation. In a TD, *ex ante*, administrative approach, the utility's average embedded cost of electricity production is compared with an average assumed market price. This approach is much simpler than the BU approach, primarily because it requires only a few assumptions and elementary calculations. However, it is also much less detailed and therefore provides fewer insights into the specific assets, liabilities, and costs that account for a utility's TC situation. FERC's revenues-lost approach is a TD method.

Transition costs can be assessed from at least two perspectives: 1. that of the utility, assuming that customers face the same prices they would have faced without retail wheeling, and 2. that of remaining retail customers, assuming that the utility's earnings are unaffected by retail wheeling. In reality, neither utility shareholders nor retail customers are likely to bear 100% of the TC losses. For analytical convenience only, we adopt the utility perspective in the following discussion.

If the utility bears all the losses, its costs are equal to the net present value of the differences in net income between the no-wheeling (Base) and retail-wheeling (RW) cases:

$$TCs = NPV \sum_{t=1}^T (Net\ income_{Base,t} - Net\ income_{RW,t}), \quad 1.$$

where *NPV* is the net present value, often calculated at the utility's return on equity for the *t* years through year *T*. Determining *T* is a difficult policy choice because the annual values of TCs can be positive for several years and then turn negative, depending primarily on the assumptions one makes about the future price of bulk-power electricity. Net income is the difference each year between the utility's revenues and its expenses, where expenses include all operating costs, depreciation, taxes, and interest payment on bonds.

If the utility keeps the sales at risk, its earnings loss (change in net income) is

$$(1 - \text{income tax rate}) NPV \sum_{t=1}^T \sum_{j=1}^N [kWh_{RW,tj} \times (\text{Utility total production cost/kWh} - \text{Market price})_{tj} + \text{rate-design adjustments}_{tj}], \quad 2.$$

where the subscript j refers to one of the N customer classes, and the term $kWh_{RW,j}$ is the annual energy loss that the utility experiences because of RW.

The first term in Equation 2 inside the summation signs is the amount of money lost because the utility now collects from wheeling customers only the market price for electricity, whereas before it collected the total cost (fixed plus variable costs) of production and purchased power. The estimates of average utility production cost and market price must be consistent with each other. Specifically, all prices and costs must be measured at the same level in the transmission and distribution (T&D) system (e.g. at the generator busbar) to consistently reflect electrical losses in the T&D system, and they must include only comparable costs (e.g. generation only with T&D costs excluded). Also, both annual averages must be weighted by electricity consumption, not by time. Because marginal cost and wholesale price generally increase with demand, consumption-weighted values are higher than time-weighted values by roughly 5–10%.

The second term represents any losses associated with rate design (i.e. non-production costs that are not fully reflected in T&D wheeling rates). For example, this term could include the annual costs of public-policy (e.g. low-income) programs that are assigned to generation. Implementation of this approach is simple. One first estimates the total production costs for each applicable rate class and then estimates, in a consistent fashion, the market price that each class would face. These calculations require only a rudimentary knowledge of the utility's production costs and the wholesale power market. Second, one estimates the effects of rate design on lost revenues. The losses associated with rate design will also differ across rate classes because the tariff designs may differ in their allocations of generation versus other costs to different classes. This process requires an understanding of utility accounting and ratemaking. The results for each of the N rate classes is then summed to obtain the utility's total TC estimate.

The term $(1 - \text{income tax rate})$ shows that any losses experienced by a private firm are offset in part by reduced federal and state income-tax payments. For example, if a utility's combined federal and state income tax rate is 36%, its shareholders will face only 64% of any losses associated with retail wheeling. Taxpayers will bear the remainder through lower tax receipts.

4.3 Criteria to Assess Methods

How should regulators decide among the various analytical and market approaches discussed above (Table 1)? When faced with conflicting claims about TCs, policymakers need a framework to assess different cost estimates and estimation approaches. We identified eight criteria related to implementation,

administrative ease, public availability of data and models, consideration of relevant assets and liabilities, the time period considered, market price and value determinations, price and value comparisons, and treatment of market forces.

Implementation describes how valuation is conducted technically and procedurally. Administrative valuation methods typically are implemented using computer models. Market valuation methods are implemented by auction, sale, spin-off, or some other market process. Implementation also refers to the need for regulatory proceedings to review estimates, estimation methods, or supporting data.

Administrative ease refers to the relative difficulty of implementing the approach and administering any associated proceedings.

Are the data and models necessary to calculate TCs publicly available or proprietary? Much of the data needed is available from reports that utilities file with their state regulators and with FERC. A proprietary model may be available through licensing agreements or other commercial arrangements.

The relevant assets and liabilities criterion indicates whether the approach includes those items that analysts agree should be included in TC estimates. The relevant categories, as discussed above, include utility-owned generation assets; long-term obligations, such as power-purchase contracts and fuel contracts; regulatory assets, such as the phase-in of an expensive power plant; and possibly public-policy programs. Public-policy programs would only be appropriate to include if the utility remains obligated to implement these programs and the costs are not recovered through an appropriate funding mechanism.

The time periods used to estimate TCs vary depending on the level of aggregation in the analysis. For example, the time periods covered for utility generation and power-purchase contracts often differ depending on the book lives of the generating units and the terms of the contracts.

Estimates of future market prices for bulk-power electricity are made either by using analytic techniques (price estimates—the basis for administrative valuation) or by observing appropriate market indicators; see (8) for examples. Price estimates can be developed either endogenously or exogenously. Endogenous price estimates are not predetermined assumptions and they are not externally imposed by the analyst; they are the result of market simulations or an analysis that explicitly accounts for the economics of plant dispatch in a region. Hence, they are an intermediate result of the analytic method used to calculate TCs. In contrast, exogenous price estimates are derived directly from an assumption or an observation about the cost of different generation options.

TC approaches invariably involve a comparison of value (or price) under regulation versus market conditions. This comparison includes three elements:

parity, return on equity (ROE), and taxes. Parity refers to whether the regulated price and the market price include comparable elements. Comparing a fully bundled residential retail rate, which includes generation, transmission, distribution, and customer service costs, to a competitive-market price for generation service is inappropriate if the objective is to estimate TCs caused by the deregulation of generation. ROE is important because it can have a substantial effect on TC estimates. TC estimates might assume that utility shareholders are held harmless and earn the full authorized ROE on these potentially stranded assets. Alternatively, the analysis might assume a lower ROE to account for the reduced risk associated with a regulator's guarantee that certain costs will be recovered. Taxes indicate whether the effects of income taxes are included in the approach, as discussed above. A dollar revenue loss to the utility does not equal a dollar loss to shareholders because the utility does not have to pay federal, state, and local income taxes on the lost revenue. More generally, development and comparison of TC estimates require attention to certain key assumptions and their internal consistency. These assumptions concern the return of, as well as the return on, equity; the time period to be used in analyzing TCs; and consistency in the determination of the market and regulated prices for individual assets and liabilities. Consistency refers to analysis at the same level in the T&D system, inclusion of generation services only, and consideration of the load shape for the customer classes in question. Market forces will affect the actions of utilities and of other participants in bulk-power markets. For example, high-cost utilities will likely respond to increased competition by cutting costs and improving the performance of their generating units (e.g. by reducing forced outage rates). Many utilities will pursue previously protected markets to increase sales. Such efforts will affect the TCs that utilities ultimately face. The wider marketplace will also respond to increased competition. Over time, electricity prices will change as more consumers and suppliers participate in competitive markets. If current capacity surpluses tighten, prices should rise, thus stimulating development of new supplies. The interaction of demand and supply over time will in turn determine future market prices, which directly affect TCs. Rose uses the term "dynamic efficiency" to describe the long-term effects of these market forces (9). Over time, supply costs for utilities and other generators will approach the industry's marginal costs of generation.

5. FACTORS THAT AFFECT TRANSITION-COST ESTIMATES

Table 2 shows some of the many factors that affect utility operations, costs, and therefore transition costs. We divided these factors into three categories.

Table 2 Factors affecting the amount of transition cost a utility faces

Factor	Wholesale market	Accounting
Generation assets		
Capital costs (initial cost, depreciation, taxes, etc)		Yes
Fixed production operations and maintenance		Yes
Variable production operations and maintenance	Yes	
Forced and planned outage rates	Yes	
Liabilities		
Power-purchase fixed costs		Yes
Power-purchase variable costs	Yes	
Deferred income taxes		Yes
Regulatory assets		
Annual nonfuel expenses		Yes
Public-policy programs that are expensed		Yes
Other costs (e.g. administrative and general expenses) not in wheeling rates		Yes
Other factors		
Load growth by customer class	Yes	
Customer-class load factors	Yes	
Customer-class loss factors	Yes	
Inflation rate		Yes
Tax rates (i.e. income, property, and revenue)		Yes
Wholesale-power prices	Yes	
Difference between wholesale purchase and sale prices	Yes	
Number of customers that choose retail wheeling	Yes	
Transmission capacity for wholesale transactions	Yes	
Ancillary-service costs		Yes
Regulatory factors		
Year retail wheeling begins	Yes	
Number of years for which TC recovery is allowed		Yes
Type and frequency of rate cases		Yes
Authorized return on equity		Yes

Regulatory factors are those that the state regulator can influence, wholesale-market factors affect the interactions between the utility and wholesale power markets, and accounting factors affect the utility's income statement and balance sheet but not its interactions with wholesale markets.

We used the Oak Ridge Financial Model to conduct the analyses presented in this and the following sections (31). First, we created a base-case utility, using historical data from the Energy Information Administration. We simulated the finances, operation, and rates of this utility from 1995 through 2005 assuming

no retail wheeling and the traditional cost-of-service regulation. Then we hypothesized a pattern of retail wheeling, starting at zero in 1995, increasing linearly to 42% of the retail load in the year 2000, and remaining constant from 2000 through 2005. We assumed that the state regulator would permit recovery of stranded costs for the 10-year period from 1996 through 2005. The utility's earnings loss (\$699 million) amounts to 45% of shareholder equity. If remaining retail customers bear all the TCs associated with retail wheeling, their rates increase relative to the non-wheeling case by a maximum of 24% in the year 2000. For additional details, see (32).

5.1 Regulatory Factors

PUCs have substantial influence over the timing and extent of retail wheeling and therefore over the TC amounts that a utility or its customers might face. These factors include the year that retail wheeling begins, the number of years for which transition costs are calculated, and the type and frequency of rate cases.

For a variety of reasons, many states have delayed the onset of retail wheeling. One motivation for such delays is the decline in TCs that the passage of time provides. The natural decline in fixed production costs is a powerful incentive to slow implementation of retail wheeling. For the base case, fixed production costs decline by 50% between 1995 and 2005; about half this decline is caused by depreciation, with the remainder caused by inflation and load growth. (During this 10-year period, the utility builds no new generating units. As a consequence, its reserve margin declines from 34% in 1995 to 6% in 2005.) Each one-year delay reduces the utility's TCs by about 18%, assuming that the utility is allowed to recover costs for a full 10-year period. A three-year delay from 1996 to 1999 cuts the amount almost in half. Of course, these results assume that state regulators and utilities can prevent retail customers from finding other, lower-cost sources of electricity (e.g. through cogeneration).

5.2 Wholesale-Market Factors

The interactions between a utility's generating resources (both its own generating units and its power-purchase contracts) and the wholesale market affect the amount of TC losses. As shown in Equation 2, TCs depend on the difference between a utility's production costs and the market price. And a utility's production costs depend on market conditions and the utility's opportunities to buy and sell power on the wholesale market.

Changes in wholesale prices affect TC estimates in exactly the same way (but with the opposite sign) as do changes in utility variable production costs. For example, a decrease in wholesale price will reduce the amount of power the utility sells on the market and will increase the amount of power it buys in exactly

the same way that an equal increase in production costs would. Because of this symmetry, we show results only for changes in wholesale prices. As wholesale prices increase, the losses caused by retail wheeling decrease. Indeed, if wholesale prices increase by more than 1.6 cents per kWh above their base-case values, retail wheeling increases earnings to utility shareholders. Conversely, as wholesale prices decrease, TCs increase.

As the number of customers that choose to "leave" the utility increases, the TC amounts increase. The loss to the utility increases linearly with the number of RW customers (i.e. the loss per RW customer does not vary with the amount of retail wheeling). The loss to remaining customers, however, increases much more rapidly. This difference occurs because, as the number of retail-wheeling customers increases, the number of remaining retail customers among whom the loss is spread decreases.

5.3 Accounting Factors

Our base-case utility has \$800 million in regulatory assets, compared with total assets in 1995 of \$4950 million. Increasing the regulatory assets by 50% increases losses by 9% (\$63 million). The base-case utility spends \$40 million a year on public-policy programs, equivalent to 2% of revenues. Eliminating these programs would cut TCs by 4%. Decreasing the fixed O&M costs of generation decreases TCs. A \$10/kW decrease in fixed costs cuts TCs by 10%, comparable to the effect of a 0.25 cents/kWh change in either marginal production cost or wholesale price.

Ancillary services are those functions performed by electrical generating, transmission, system-control, and distribution equipment and people to support the basic services of generating capacity, energy supply, and power delivery. These services cost about 0.4 cents per kWh. Generating capacity accounts for many of these services and their costs. A utility that can sell these ancillary services to retail-wheeling customers can use the fixed-cost portion of these revenues to offset what would otherwise be TCs. Each 0.1 cents per kWh of ancillary-services charge reduces its losses by 3%.

Changes in inflation rate, customer load factors, T&D losses, or load growth all have very small effects on TC estimates.

5.4 Summary

The analyses discussed above show that, although many factors affect estimates of transition costs, only a few factors really matter (Figure 4). The key variables that most affect losses include the year that retail wheeling begins, wholesale prices (or, equivalently, utility marginal production costs), the percentage of customers that wheel, fixed production costs, regulatory assets, and charges for certain ancillary services. Many other factors, including frequency and type of

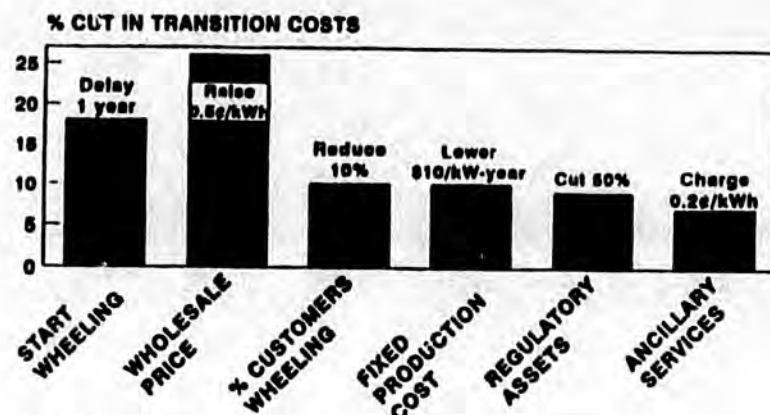


Figure 4 Effects of the key factors that influence transition costs. The base case against which these results are developed assumes that retail wheeling begins in 1996, the wholesale price is 2.5 cents per kWh (and the marginal cost of the utility's generation is 2.4 cents per kWh) in 1995, 50% of the commercial/industrial customers plus 25% of the residential customers are wheeling by the year 2000, fixed production costs are \$186 per kW in 1995, and no ancillary-services charge is levied.

rate cases, public policy-program costs, inflation rate, customer load factors, transmission and distribution loss factors, and load growth, have only small effects on the losses caused by retail wheeling.

6. STRATEGIES TO ADDRESS TRANSITION COSTS

Given the large dollar amounts often associated with TCs, regulators, utilities, their customers and suppliers, and others have a strong interest in seeking ways to offset these costs. Strictly speaking, transition costs, because they reflect sunk costs and future obligations, cannot be "mitigated." However, utilities and their regulators may be able to reduce other costs and thereby offset some of what would otherwise be TCs. Most of the strategies we identify involve shifting costs over time or among different segments of the economy. We discuss four major types of strategies to address transition costs: market actions, depreciation actions, rate-making actions, and utility cost reductions. See (33) for additional details on these strategies.

6.1 Market Actions

Market actions affect the market structure for electricity or rely on market mechanisms, such as auctions or sales, to affect the distribution of TCs. A prominent strategy calls for the rapid and broad opening of retail electricity markets (i.e. retail wheeling) at the earliest possible date. Monopoly franchises

for retail electricity sales are eliminated, and all consumers have a choice of electricity suppliers. Such a strategy maximizes both competitive pressures on suppliers and consumer welfare gain.

An alternate strategy is to delay the onset of competition and create a more deliberate opening of retail electricity markets. Retail access is eventually granted to all consumers, but not until several years after the initial group gets access. A variant on this strategy is to give all consumers access at the same time but delay the onset of access by several years. This strategy sacrifices a portion of consumers' welfare gain to enable producers to recover a larger share of their sunk costs.

Divestiture, selling all or part of a utility's generation portfolio to separate companies, is widely discussed (34). Divestiture could address several issues. The sale provides a readily identifiable market value for the asset(s), which is necessary to estimate TCs, and also separates the unregulated generation business from the regulated T&D business. Some analysts argue that utility divestiture is necessary to ensure competitive markets and to reduce potential conflicts between unregulated and regulated business operations. Divestiture also reduces the possibility that a utility will exercise its monopoly power over transmission to benefit its competitive generation position.

A divestiture strategy is most commonly applied to generation, but analysts also discuss the sale of transmission assets. (Revaluing generation, transmission, and distribution assets is a similar strategy, except the utility retains ownership of all assets.) This discussion is motivated by the belief that the market value of transmission assets exceeds their book value. In such cases, the above-book proceeds from a transmission sale are used to partially offset the below-book market values of certain generating assets. Setting aside potential legal issues, problems arise for transmission-poor utilities faced with potential TCs (35).

Marketing existing excess capacity or energy, or capacity or energy freed by departing customers, is a clear strategy to increase revenues and thereby offset TCs. Indeed, FERC's approach defines mitigation as the sale of available energy at market prices. Some proposals, including FERC's, give departing customers the opportunity to market energy freed by their departure from the utility.

Finally, improving system load factors, either by reducing peak demand or by increasing off-peak energy sales, should lower utility costs. Such a marketing strategy should affect the amounts of TCs a utility will face.

We now quantify several of these market actions (Table 3). (As in the previous section, we analyze TC losses as if they all fall on utility shareholders.) The timing and extent of retail wheeling can substantially affect the losses a utility will face. For the base case discussed above, a two-year delay in the start of retail wheeling from 1996 to 1998 reduces the utility's losses by 33%. A

Table 3 The effects of different strategies to address transition costs

Transition-cost strategy	% change in utility transition costs ^a
Market actions	
Accelerate RW with full implementation by 1998 instead of 2000	+72
Delay RW by two years	-33
Delay RW by two years and cut amounts by 50%	-70
Increase system load factor 5 percentage points (from 56% to 61%) by cutting peak demands	+20
Increase sales by 10% and hold system peaks unchanged (increase load factor from 56% to 62%)	-17
Charge 0.2¢/kWh for capacity-related ancillary services	-6
Depreciation options	
Accelerate depreciation schedules for nuclear (9 years) and coal (16 years) plants and for regulatory assets (6 years)	+34
Accelerate depreciation schedules for nuclear (9 years) and coal (16 years) plants and for regulatory assets (6 years); extend depreciation from 50 to 75 years for T&D	+28
Utility-cost reductions	
Lower customer-service costs from \$70 to \$45/customer-year	-13
Lower A&G costs from \$176 to \$100/customer-year	-37
Lower T&D O&M costs from \$23 to \$11/kW-year	-28
Lower fixed O&M costs for nuclear and coal plants by \$10/kW-year	-16
Make must-run contract dispatchable at 3¢/kWh and pay owner lost profits	-9
Lower fixed costs for power-purchase contracts from \$45 to \$30/kW-year	-12

^aThe base-case loss is \$699 million, equivalent to 45% of shareholder equity.

two-year delay, combined with a 50% reduction in the ultimate amount of retail wheeling would cut the utility's losses by 70%. On the other hand, accelerating full implementation of retail wheeling by two years, from 2000 to 1998, would increase the utility's losses by 72%.

If the utility is able to cut peak demands without affecting sales, its load factor will increase. An 8% reduction in peak demand yields an increase in system load factor from 56% to 61%. Although such a strategy lowers utility costs and average retail prices, the revenue reductions are greater than the cost reductions. Cutting peak demand increases the utility's TCs by 20%. On the other hand, if the utility improves its system load factor by increasing off-peak sales by 10% while holding peak demand fixed, its costs will decrease more than its revenues, and its TCs will decline by 17%. The difference in results between these two cases occurs because of the utility's retail rate tariffs. These results suggest that the utility, with approval from its PUC, may want to revise these allocations in response to changes in system load factor.

Finally, the utility might be able to sell generation-related ancillary services, such as regulation and operating reserves. We assume that the utility can sell these capacity-related services for 0.2 cents per kWh more than the operating costs associated with these services. Selling these services to wheeling customers would cut TCs by 6%.

6.2 Depreciation Options

Depreciation expenses for unamortized generation plants contribute directly to fixed generation costs. As a result, analysts have devoted considerable attention to examining how plant depreciation could be modified to address TCs.

Traditional regulation permits lengthy depreciation periods for the capital-intensive investments in generating facilities. For large power plants, these depreciation schedules may last for up to 40 years. Accelerating depreciation shortens the time during which capital costs are recovered. Accelerated book depreciation increases depreciation expenses over the shortened depreciation period but eliminates these expenses once the plant is fully amortized. The primary motivation for accelerated depreciation is to increase the recovery of a utility's fixed costs while its retail franchise is still intact.

Because accelerated depreciation increases depreciation costs immediately, an alternative is to offset these cost increases by decelerating depreciation of other utility assets. For most utilities, the T&D plant is the largest capital asset after generation. Thus, one strategy is to offset the increased costs of accelerated depreciation by decelerating depreciation of transmission or distribution assets, or both. Southern California Edison proposed such a strategy to more rapidly recover shareholder investment in a nuclear plant and still hold retail rates constant (36).

A depreciation reserve is the accumulated annual depreciation expense on a utility's balance sheet that is deducted from the plant-in-service account. The depreciation reserve reflects the amount of investment in the plant-in-service that has been recovered from ratepayers. Transferring depreciation reserves from T&D accounts to generation-plant accounts is an explicit strategy to revalue the associated assets. Such a transfer will reduce the net book value of the generation plant and increase the net book value of the T&D plant by the amount transferred. South Carolina Electric & Gas proposed that this strategy be used to reduce the net book value of a nuclear plant to the average value of nuclear plants in the region. FERC rejected this proposal because it would have shifted costs from generation to transmission.

Table 3 quantifies several of these depreciation options. In the base case, the 800-MW nuclear unit is not fully depreciated until 2009, and the 750-MW coal unit is not fully depreciated until 2016. Accelerating depreciation so that

both units are fully depreciated by 2000 raises TCs by 30% (16% from the nuclear unit and 14% from the coal unit). This strategy increases losses for the first several years (through 2000) and then reduces losses thereafter. However, the net present value of the increases is greater than that of the decreases. The utility had a total of \$800 million in regulatory assets as of 1995. Accelerating the depreciation of these assets from 12 to 6 years increases TCs by almost 4%. The utility's losses increase because more of the depreciation occurs earlier and therefore has a larger effect on the net present value of the losses. However, if this asset was depreciated even faster, over four or fewer years, the utility's TCs would decline. In this case, most of the costs would be recovered before many of the utility's customers became eligible for retail wheeling.

Extending the book-depreciation lifetime of T&D assets from 50 to 75 years reduces utility TCs, but only slightly. Such a strategy can help to mitigate the effects of accelerated depreciation of generation assets. In this case, the combined strategy increases the utility's loss by 28%, six percentage points less than would occur without the extended T&D depreciation schedules.

6.3 Rate-Making Actions

In most jurisdictions, current rate design recovers variable costs and some portion of fixed costs through a volumetric energy charge. Even for those customers that pay energy and demand charges, some fixed costs are recovered through the energy charge. A tariff for all ratepayers that includes an energy rate close to the utility's marginal costs, and a fixed charge close to the utility's fixed costs, would provide a more accurate price signal. The utility is able to compete successfully for sales during times when the utility is the low-cost provider, thus avoiding uneconomical bypass of the utility's generation system. The lower energy rate that will result for most utilities from such a rate restructuring will also increase electricity demand (37). Such demand increases will increase revenues and reduce TCs.

Perhaps the simplest example of rate unbundling is the rate-restructuring option described above, which provides more appropriate price signals to consumers. Electricity services and costs can be further unbundled to include T & D costs and ancillary services costs. Unbundling generation services in addition to power delivery, energy, and capacity may help address transition costs. For example, while the costs of ancillary services are a small part of a utility's total costs, charging for these costs may reduce TCs.

Performance-based rate making (PBR) replaces cost-of-service rate making with either a price or revenue cap that is adjusted periodically for inflation and a minimum productivity-improvement target. A PBR mechanism that shifts market risks from consumers to the utility could encourage the utility to reduce costs and improve productivity. PBR is attractive as a TC strategy when some of these cost savings are credited toward the utility's TCs.

Charging departing customers exit fees is the opposite of charging captive customers for TCs. Most, but not all, proposals link the exit fee to those embedded utility costs incurred on behalf of the departing customer. Exit fees can be structured as a lump-sum payment or as a stream of payments. Exit fees attract considerable interest from utilities and regulators, and the use of exit fees is the strategy FERC selected to address TCs for wholesale customers. A properly structured exit fee makes the utility indifferent (with regard to recovering the utility's historical investment on the customer's behalf) to a customer's decision to leave or stay and discourages uneconomical bypass of the utility's system.

Access charges for transmission or distribution service can be structured to include TC recovery. The access charges can be fixed (dollars per customer) or volumetric (cents per kWh). The fixed charges could be collected as a lump sum or as a payment stream. Charges set for transmission access are under FERC jurisdiction, while charges for distribution access are under state jurisdiction. Access charges are appealing because they recover TCs from all electricity users except those few that are completely disconnected from the utility grid. This is the approach selected by the California Legislature in its specification of a competition transition charge.

To examine the effects of exit fees, we estimated one-time exit fees for residential and commercial/industrial (C/I) customers in two ways. First, we based the exit fee on the utility's losses during the first year of retail wheeling (1996) and assumed that the utility would be entitled to that amount for each of the 10 years in the original cost-recovery period. Second, we based the exit fee on the utility losses for each of the 10 years. The first approach led to higher exit fees, which would overcompensate the utility for its losses. This overcompensation is a consequence of the declines from year to year in annual TCs, which drop because of load growth, decreases in depreciation expense, and increases in wholesale prices.

6.4 Utility Cost Reductions

To be considered as TC strategies, most of the following options require regulatory approval to allow cost reductions to be used to offset TCs. Cost reductions that enhance the quality and level of service provided are economic-efficiency gains and thus are distinguished from strategies that shift costs over time or among different economic actors. Generation-cost savings could come from reducing plant heat rates and O&M costs and from retiring uneconomical plants. Competitive forces from a restructured electricity-generation industry will induce utilities to pursue such cost reductions to retain existing customers and to attract new ones. However, these cost-cutting pressures raise concerns that plant maintenance and safety will suffer, particularly for nuclear plants. Utilities will also be motivated to reduce costs in other areas, such as T&D and customer service, if these reductions decrease TCs for shareholders.

Utilities with above-market power-purchase contracts can reduce costs by restructuring these contracts. Depending on the history of the specific contract and the utility's financial status, the utility may be able to restructure the contract or buy out the above-market portion of the contract at a discount. Power producers will have incentives to renegotiate contracts if maintaining the existing contracts threatens the financial survival of the purchasing utility. In addition, provisions of certain power-purchase contracts may become incentives to renegotiate once a competitive generation market is established. Finally, depending on their debt costs and discount rates, some producers may prefer a contract buyout with up-front payments rather than continuing to receive payments over extended periods during a time of substantial changes in market structure and operation.

We quantify several of these utility-cost options in Table 3. If the utility could lower its customer-service costs from \$70 to \$45 per customer-year, its losses would drop by 13%. If it could cut its administrative and general costs from \$176 to \$100 per customer-year, its TCs would drop by 37%. Finally, cutting its T&D O&M costs from \$23 to \$11 per kW-year would cut losses by 28%.

If the utility lowers the fixed O&M costs for its nuclear and coal units by \$10 per kW-year, its losses will drop by 16%. If the must-run 600-MW contract can be dispatched at its running cost (assumed to be 0.3 cents per kWh below its contract payment of 3.3 cents per kWh), its capacity factor will decline from 75% to 17%. The savings that accrue from the utility's ability to obtain cheaper electricity from its own plants and from other purchases is equivalent to 19% of its losses. If, as seems more realistic, it must compensate the owner of this contract for its losses, the utility's losses are cut by only half as much. If the utility can lower the fixed payments from \$45 to \$30 per kW-year for the 1600 MW it has under contract, its TC losses will decline by 12%. Whether the kinds of cost reductions outlined above are reasonable depends on the individual circumstances facing each utility. For example, a utility might have high distribution costs, not because it is inefficient, but because its customer density is low or its geographic area is subject to extensive and destructive storms.

6.5 Summary

The results discussed above apply only to the hypothetical utility we created. The benefits and costs of the different strategies discussed here will depend on the utility's specific situation concerning its above-market costs in utility-owned generating units, long-term contractual obligations, and regulatory assets. A few of the strategies discussed here have the potential to substantially affect the TCs that a utility would otherwise face. Changes in the start date, pace, and extent of retail wheeling could have large effects in shifting costs between utility shareholders and retail customers. Charging an exit fee to departing customers would have comparable effects. Cutting various nongeneration O&M costs as well as the nonfuel O&M costs for generating units could have substantial

cost-reduction effects, although the savings for the utility examined here may be unusually large.

At the other end of the spectrum, extending the book-depreciation schedules for a utility's T&D investments is likely to have only small effects on TC amounts. (Indeed, all the depreciation options considered here shift costs over time but do not affect the total transition costs.) Similarly, shortening the depreciation period for regulatory assets also has only a limited effect on a utility's potential losses. Finally, charging wheeling customers for ancillary services will have a modest effect on TC losses.

7. CONCLUSIONS

The US electricity industry is in the midst of major changes. Today's electricity industry is dominated by vertically integrated utilities, which enjoy retail-monopoly franchises. Tomorrow's industry may involve separate companies that generate, control, transmit, and distribute electricity. The generation sector may be competitive and largely free of economic regulation. The transition from one type of structure to another will, for some utilities, expose costs that cannot be sustained in competitive markets.

These transition costs are the potential monetary losses that utility shareholders or other parties might experience because of structural changes in the electricity industry. Roughly speaking, transition costs reflect the difference between regulated retail electricity prices for generation services and the competitive-market price of power.

These costs already exist and are, in general, being paid for by today's retail electricity consumers. Legislators, regulators, and others need to address these costs up front and establish clear rules on how they will be measured and shared among different groups. Government failure to render clear policy decisions will cause serious problems, including extensive litigation, delays in the implementation of competitive markets, and de facto "deals" that favor economically and politically powerful interests. Finally, dealing with transition costs is, as the name implies, not an enduring issue. Once the transition from today's vertically integrated, regulated, monopoly industry to a more competitive industry is complete, this issue will disappear. However, the large dollar amounts at stake ensure that transition costs will be a critical issue for several years.

Transition costs include four types of costs: assets, primarily in expensive power plants and excess generating capacity; liabilities, primarily in power-purchase contracts, fuel-supply contracts, and deferred income taxes; regulatory assets, whose value is based on regulatory decisions rather than on market forces; and public-policy programs, including tax collection, demand-side management programs paid for by all customers, and special programs for low-income customers. Unlike the first three categories, the costs in this category

are current, not sunk; these costs could be discontinued if the programs were stopped.

Estimates of transition costs vary widely, with many falling in the range of \$100-\$200 billion for the United States as a whole. By comparison, total shareholder equity in US utilities is about \$190 billion. Not only is a great deal of money at stake, but that money is distributed unevenly across utilities and regions. Certain regions (such as the Pacific Northwest) have almost no exposure to transition costs, while other regions (such as California and the Northeast) face substantial problems.

Utilities and regulators can use a variety of approaches to calculate transition costs, categorized along three dimensions. The first dimension is the use of administrative versus market procedures to value the assets in question. Administrative approaches use forecasting, modeling, or other analytical techniques to estimate transition costs. Market valuation relies on the purchase price of particular assets to determine their market values. The second dimension concerns when the valuation is done, either before or after restructuring is completed. The third dimension concerns the level of detail involved in the valuation, top-down versus bottom-up valuation.

Regardless of the method used to estimate transition costs, one must make certain assumptions. Although many factors affect the calculation of transition costs, only a few factors make a big difference. The most important factors include future market prices of electricity, utility marginal costs of production, when retail wheeling begins, extent of retail wheeling, amount of utility regulatory assets, and utility fixed production costs. On the other hand, certain factors are likely to have very little effect on estimates of transition-cost amounts, including public-policy program costs, the inflation rate, load growth, customer load factors, and transmission and distribution system loss factors.

Of the critical factors that affect transition costs, some can be influenced by the utility and some by the PUC, and some are essentially beyond the control of either party. As examples, the PUC can affect the start date and extent of wheeling, although market forces may overwhelm regulation where large price disparities exist; and utilities can seek to cut their fixed and variable production costs. But wholesale prices—the most important factor—are largely independent of utility or PUC actions.

Strictly speaking, transition costs, because they reflect sunk costs and future obligations, cannot be mitigated. However, regulators can allocate these costs among different groups. In some cases, regulators and utilities can find ways to cut costs and can then use these savings to offset what would otherwise be transition costs.

Because of these large dollar amounts, state and federal regulators are committing considerable time and attention to transition costs. The Federal Energy Regulatory Commission devoted almost 25% of its 1996 landmark decision

(Order 888) on open-access transmission to transition costs. Similarly, the California Public Utilities Commission recognized the critical role that transition costs play in restructuring the California electricity industry "to assure the continued financial integrity of California's investor-owned utilities..." The California Legislature affirmed the Commission's support for utility recovery of transition costs.

The New Hampshire and Vermont regulators emphasized the role of utilities in mitigating transition costs. Both commissions plan to allow cost recovery only for those costs that remain after utilities have exhausted their mitigation opportunities. And both states adopted a broad view of mitigation, including actions that some might not consider mitigation, such as utility writeoffs of uneconomic assets or disallowance of costs associated with rates that are above the New England regional average.

Regulators and legislators must pay close attention to transition costs, primarily because of the large amounts involved in many states. Some of the transition-cost issues discussed here are analytical. But others are primarily policy issues. In particular, the allocation of transition costs among different stakeholders is a critical policy issue on which legislators and regulators will play a key role.

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[BACK TO ABOUT DEREGULATION](#)

A GLOSSARY

UNDERSTAND THE TERMINOLOGY OF DEREGULATION

The following is a glossary of terms that will help you better understand the electric industry, deregulation, and the Pilot Program.

[A](#)/[B](#)/[C](#)/[D](#)/[E](#)/[F](#)/[G](#)/[H](#)/[I](#)/[J](#)/[K](#)/[L](#)/[M](#)/[N](#)/[O](#)/[P](#)/[Q](#)/[R](#)/[S](#)/[T](#)
[U](#)/[V](#)/[W](#)/[X](#)/[Y](#)/[Z](#)

Affiliate

A company that is controlled by another or that has the same owner as another company. [Top](#)

Aggregator

A firm, licensed by the commission, that signs up a large group of consumers to bargain on their behalf for the lowest possible price for electricity. The firm "aggregates" or combines many smaller customers into one large customer for purposes of negotiation. It purchases the electricity for the group. [Top](#)

Base Load

The minimum energy level a company must provide to its customers on a constant basis. [Top](#)

Basic Service

The four charges for generation, transmission, distribution, and transition that all customers must pay in order to retain electric service. [Top](#)

Broker

A firm, licensed by the commission, that acts as an agent or "middle man" in the sale and purchase of electricity but never owns the electricity and typically does not own generating facilities. [Top](#)

Bulk Power Market

Wholesale purchases and sales of electricity. [Top](#)

Chapter 56

The Public Utility Commission's regulations that establish rules for payment of utility bills, requests for service, payment of deposits, billing, termination of service and complaint handling. These regulations are to protect residential customers of regulated electric, gas, water, steam heat, and sewer companies in

Pennsylvania.[Top](#)**Commission**

The Pennsylvania Public Utility Commission.[Top](#)

Conservation

Reducing a customer's electricity use to decrease the need to generate electricity.[Top](#)

Consumer Education

Efforts to provide consumers with skills and knowledge to use their resources wisely in the marketplace.[Top](#)

Customer Assistance Programs (CAPS)

Alternative collection program set up between a utility company and a customer that allow customers to pay utility bills on a percentage-of-the-bill they owe or percentage-of-customer-income instead of paying the full amount owed. These programs are for low income people who can't pay their bills. These customers must agree to make regular monthly payments based on their new payment plans.[Top](#)

Daily Peak

The maximum amount of energy or service demanded in one day from a company or utility service.[Top](#)

Demand

A measure of customer or system load requirements over a measured period of time.[Top](#)

Departing Member

A member consumer served at retail by an electric cooperative corporation that has given notice of intent to receive generation service from another source or that is otherwise in the process of changing generation suppliers. These persons shall nonetheless remain members of the electric distribution cooperative corporation for purposes of distribution service.[Top](#)

Deregulation

Removal or relaxation of regulations or controls governing a business or service operation such as utilities.[Top](#)

Distribution

The local wires, transformers, substations, and other equipment used to distribute and deliver electricity to

end-use consumers from the high-voltage transmission lines.[Top](#)

Distribution Charges

Part of the basic service charges on every customer's bill for delivering electricity from the electric distribution company to your home or business. The distribution charge is regulated by the Public Utility Commission. This charge will vary according to how much electricity you use.[Top](#)

Distribution Line

The local part of an electric system that delivers electricity to most customers.[Top](#)

Distributive Power

A packaged power unit located at the point of demand. While the technology is still evolving, examples include fuel cells and photovoltaic applications.[Top](#)

ECAR

Council Ohio, Western Pennsylvania (Allegheny, Penn Power, Duquesne).[Top](#)

Electric Distribution Company (EDC)

The company that owns the power lines and equipment necessary to deliver purchased electricity to the customer.[Top](#)

Energy Conservation

To reduce or manage energy consumption in a cost-effective manner.[Top](#)

Energy Services Company (ESCO)

A company offering specialized or customized services for efficiency or financial savings to customers.[Top](#)

Escape Provision

A contract provision which allows a party such as an electric customer to get out of it. Usually, there is a penalty.[Top](#)

Fixed Price

A price which remains the same, usually for a set time period.[Top](#)

Flat Rate

A fixed charge for goods and services that does not

vary with changes in the amount used, volume consumed, or units purchased.[Top](#)

Formal Complaint

A written dispute or disagreement about a utility problem filed by a consumer with the Public Utility Commission. A formal complaint is assigned to an Administrative Law Judge (ALJ) who holds hearings to develop a record. After the hearings, the judge issues a decision. (See informal complaint.)[Top](#)

Generation

Production of electricity from a power plant.[Top](#)

Generation Charges

Part of the basic service charges on every customer's bill for producing electricity. Through deregulation, generation service is competitively priced and is not regulated by the Public Utility Commission. This charge depends on the terms of service between the customer and the supplier.[Top](#)

Green Power or Greencos

Demand side management and other non-polluting sources of energy generation.[Top](#)

Grid

A network for the transmission of electricity throughout the state or nation.[Top](#)

Gross Receipts

The total revenue for a calendar year for all electric distribution companies and electric generation suppliers which are derived from the sales of electric energy.[Top](#)

Hourly Metering or Time of Use Metering

Tracking or recording a customer's consumption during specific periods of time that can be tied to the price or energy.[Top](#)

Informal Complaint

A dispute or disagreement about a utility problem filed by a consumer with the Public Utility Commission's Bureau of Consumer Services (BCS). A BCS investigator reviews the informal complaint and provides the customer with a response to their dispute. Most responses are in the form of a decision that the customer or company can appeal. If an informal complaint is appealed, it becomes a formal

complaint. (See Formal Complaint.)[Top](#)

Intangible Transition Charge

The amounts on all customer bills, collected by the electric utility to recover transition bond expenses.[Top](#)

Interruptible Rate

A special utility rate given to those who agree to have their service reduced or temporarily stopped as part of an agreement with the utility company. Circumstances for service interruptions can be period of high demand or high cost periods of short supply for the utility and/or system emergencies.[Top](#)

Investor-owned Utility

A utility company owed and operated by private investors.[Top](#)

Kilowatt (kW)

(1) A measure of demand for power during a preset time-minutes, hours, days, months; (2) 1,000 watts - Ten 100 watt light bulbs use one kW of electric power.[Top](#)

Kilowatt-hour (kWh)

The basic unit of electric energy for which most customers are charged. The amount of electricity used by ten 100-watt light bulbs left on for 1 hour. Consumers are charged for electricity in cents per kilowatt-hour.[Top](#)

Load

The amount of electricity being used at one time by a customer, circuit or system.[Top](#)

Load Profile

Information on a customer's usage over a period of time, sometimes shown as a graph like the one on the bill.[Top](#)

Load Management

Shifting use of electricity from periods of high demand to periods of lower demand, when the cost of electricity usually is lower.[Top](#)

Marketer

A company, licensed by the Commission, that buys and resells electricity, but that typically does not own generating facilities.[Top](#)

Non Basic Service

Any category of service not related to basic services (generation, transmission, distribution and transition charges). [Top](#)

Office of Consumer Advocate (OCA)

A government office that represents the interest of residential utility consumers before the Public Utility Commission in rate and service cases and before other state and federal regulatory agencies and courts. [Top](#)

Office of Small Business Advocate (OSBA)

A state government office that represents the interests of small business consumers by participating in PUC rate cases and other state and federal regulatory cases. [Top](#)

Off-Peak/On-Peak

Blocks of time when energy demand and price is low (off-peak) or high (on-peak). [Top](#)

Pilot

A utility program offering a limited group of customers their choice of certified or licensed energy suppliers on a one year minimum trial basis. [Top](#)

Power Pool

Combining electric power supplies. Two or more interconnected electric systems planned and operated to supply power in the most reliable and economic manner. (POOLCO) [Top](#)

Price Cap

Situation where a price has been determined and fixed. [Top](#)

Public Input Hearings

Meetings where consumers can give input to the PUC. Sworn and unsworn testimony to the PUC judge and to the utility, consumer advocate and PUC staff. The PUC conducts hearings in the service area of the utility who requested the rate increase. Sometimes consumers can point out problems with the quality of the utility's service, management, or policies which would affect the outcome of the case. [Top](#)

Public Utility Code

The law which sets the powers and the duties of the Pennsylvania Public Utility Commission. It also sets many of the guidelines the PUC uses for utilities' rates and service standards.[Top](#)

Public Utility Commission (PUC)

The state regulatory agency that provides oversight, guidance and direction to electric public utilities.[Top](#)

Real-Time Pricing

Rates that reflect the actual cost of providing service at a given time creating fluctuating prices.[Top](#)

Regulations

A rule or law established by the federal or state government which sets procedures that a utility must follow.[Top](#)

Reliability

The providing of adequate and dependable generation, transmission and distribution service.[Top](#)

Renewables

Includes technology such as solar photovoltaic energy, solar thermal energy, wind power, low head hydro power, geothermal energy, landfill and mine based methane gas, energy from waste and sustainable biomass energy.[Top](#)

Resellers

Companies that purchase utility service from a wholesaler and resell it to consumers.[Top](#)

Restructuring

The reorganization of traditional monopoly electric service to allow operations and electric charges to be separated or "unbundled" into generation, transmission, distribution and other services. This will permit customers to buy generation services from competing suppliers.[Top](#)

Retail Wheeling

Also known as retail customer choice -- A utility company is required to transport electricity from a generating plant it does not own directly to its retail customers. This gives retail customers the ability to purchase electricity from the sources they choose.[Top](#)

Retail Customer Choice

Rural Electric Cooperative

Securitization

Spot Market

Stranded Benefits

Stranded Commitment

Stranded Investments

Supplier (Electricity Supplier)

Title 52

Transition Charge

Transmission

Interconnecting electric lines which move high voltage electricity from where it is produced to the point of distribution to customers. [Top](#)

Transmission Charges

Part of the basic service charges on every customer's bill for transporting electricity from the source of supply to the electric distribution company. The Public Utility Commission regulates retail transmission prices and services. This charge will vary with your source of supply. [Top](#)

Unbundling

Breaking down services offered into parts so each part can be billed. [Top](#)

Universal Service

Policies, protections and services that help low-income customers maintain electric service. [Top](#)

Utility Competition

Two or more electric suppliers providing the same or similar goods or services in the same marketplace and for the same customers. [Top](#)

Variable Price

A price which can change by the hour, day, month etc. [Top](#)

Weatherization

Modifying a home or structure to conserve energy. Methods include: Sealing window and door frames with caulking or gaskets, installing storm doors and windows and adding or increasing insulation. [Top](#)

Wheeling

The transmission of power that has been generated by one entity over lines of another utility system. [Top](#)

Wholesale Competition

A market structure where municipal and other utilities can exercise choice in electricity suppliers in order to meet customer needs. [Top](#)



Alaska

Rural

Electric

Cooperative

Association, Inc.

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Electric Service for 357,000 Alaskans

October 10, 1997

Representative Norman Rokeberg
Alaska State Legislature
716 West 4th Avenue, Suite 640
Anchorage, AK 99501

Dear Representative Rokeberg:

This letter is in response to your letter of August 18, 1997 in which you posed a number of questions regarding HB-235 and the issue of deregulation in the State of Alaska.

Many of my responses are subjective in nature because no one really knows what the long term impact of electric utility deregulation will be. One thing seems certain, though: the end result will be greater regulation than we presently have. One need only look at the impact of telecommunication deregulation on the Alaska Public Utilities Commission (APUC) work load to draw this conclusion.

With one primary exception, the electric industry in Alaska has opposed deregulation. This reflects the fact that almost all of the utilities in Alaska are consumer owned and don't feel the profit motive to try to take away a neighbor's customers. They are already in the mindset of working to provide the lowest possible rates to their members. However, perhaps more importantly, we don't have the infrastructure in Alaska to allow for full, open, competitive choice. In the Lower 48 states, there are a multitude of transportation paths by which electricity can be brought to a prospective customer. In Alaska, we don't even have an unconstrained transmission system from Anchorage to Fairbanks, nor, in some cases, even across adjoining service territories. If deregulation is required by federal law, criteria should be set at the state level to insure that all classes of consumers can participate on a "level playing field" and are protected from rate increases.

As you know, approximately 90% of the electricity generated by utilities in Alaska comes from consumer owned utilities. Under this ownership makeup, the boards of directors and managers of the utilities have maximum incentive to keep the cost of electricity as low as possible. In the Lower 48, almost 75% of the generation comes from investor owned utilities (IOUs) which have profit motive as their driving force. With IOUs, there is the tug and pull of competition to drive the competitor out of the market place with predatory pricing in pursuit of an unregulated monopoly that then allows price gouging. We are not dealing with a simple product here in Alaska where market forces will quickly keep prices in check.

In the Lower 48 with the mature transmission line system in place, there are numerous generation choices and the possibility of an unregulated monopoly is probably slight. In each village of Alaska, there is only one generation choice. In the interconnected Railbelt, there are only three generation choices (Chugach, Anchorage ML&P, and Golden Valley) and their rates are remarkably equal.

DEMOCRACY IN ACTION

Outsiders can come in and try to build new generation, but that takes a lot of time, significant investment, adequate zoning, and compliance with environmental regulations. It also creates the duplication that the current system was set up to avoid. While this outsider is attempting to get up and running, the local utility will probably change its price structure (at the expense of other customers) to undercut the new competitor.

As mentioned above, the cost of electricity from the Railbelt's three generation and transmission utilities is very similar. They are also all three consumer owned with little surplus cash as might be expected with an IOU. Consequently, none of the three have a significant economic advantage over each other outside of the actual makeup of their consumers (one may have a higher number of business verses residential customers). Under competition, there may be some minor savings that could be realized by tightening up on overhead expenses, but as a general rule, this is not going to result in dramatic reductions in their overall rates. Furthermore, unlike the telecommunications industry, we are not going to see any quantum breakthroughs in new technology in the power generation field.

Certainly, we will see technology advances in fuel cells, wind generation, storage devices, remotely-controlled operations, and computer-driven internal combustion and turbine-driven prime movers, but these will generally result in gradual reductions in the cost of power production. Where then, will the rate reductions come from that the three Railbelt utilities will use to compete with each other? Very simply, they will "rob Peter to pay Paul." I wouldn't be so concerned if they were all investor owned utilities where outside owners would take the hit, but as consumer owned utilities, it seems that they will just be forced to "eat their young," so to speak.

We would all like to see the industry run as efficiently as possible, and acknowledge that some form of deregulation will probably come to Alaska. We hope to shape the form of deregulation to give maximum economic advantage to all consumers without sacrificing the gains that we have made in Alaska over the past 20 years. We look forward to working with you and your committee to this end. Following are the responses to the questions that you asked.

1. Should APUC be given explicit statutory authority to allow competition?

- If APUC is given authority to allow competition without Legislative guidance, then unbridled deregulation will have come to Alaska. So the bigger question is: "...is deregulation good for Alaska, and if so, what should it look like?" Everyone has their own opinion on this issue based on their past experience and general philosophy. With deregulation, APUC will become a much bigger agency than what it is now. Just look at the number of docket items that they have to deal with now that the telecommunications industry has become "deregulated." The electric utility industry believes that the individual boards of directors can make better rate choices for their customers than can APUC for the entire industry. Nevertheless, if deregulation is to be imposed, we believe that HB-235 both gives APUC the authority to allow deregulation and strict criteria to protect all classes of customers.

2. Are there any private investor owned electric utilities? How many are there and what are the company names, parent company names and where is the home office located?

- There are 23 investor owned utilities in the State of Alaska providing about 9% of the total electric utility sales. A listing of these utilities and their addresses is included in Attachment 1.

3. *Does federal and state law allow private investor owned companies to purchase public electric cooperatives? If yes, under what conditions?*
 - To our knowledge, there are no prohibitions on investor owned utilities buying either cooperatives or municipal utilities. In both instances, the investor owned utility would need to buy out the debt and capital credits of the member owned utilities. This could represent quite a penalty to the ratepayers as much of the municipal debt is tax exempt, and virtually all of the cooperative debt is at a federally subsidized rate.
4. *Generally speaking would an investor owned buyout of a public cooperative require 50% plus 1 of the current subscribers to vote yes or would the public cooperative by-laws govern voting percentages?*
 - The buyout formula is generally spelled out in the by-laws of each cooperative. Some are quite stringent requiring two thirds of a fifty percent response. I have not polled the cooperatives to find out what the voting requirements are at each different utility.
5. *How would the cooperative assets previously financed with federal or state dollars be sold or accounted for in an investor owned buyout?*
 - See response to question 3 above. Basically the federal debt would need to be defiesed. Disposition of state debt would be dependent upon the covenants of the State lending agency. Grants, on the other hand, become the assets of the cooperative, and, unless stipulated to the contrary in the grant agreement, would be eligible to be transferred at the discretion of the negotiating parties.
6. *Have there been any public electric cooperatives purchased by private investor owned companies in Alaska?*
 - Yes. Glacier Highway Electric Cooperative in Juneau was bought out by Alaska Electric Light and Power in the late 1980's. This consolidation eliminated competition in the Juneau area, but APUC economic regulation has helped to insure that AEL&P receives a fair rate of return on its investment and that the ratepayers do not get hurt. I think that each utility buyout regardless of which way it goes has to be evaluated on its own merits. For instance, AVEC, which is a cooperative, attempted to buy out Bethel Utilities, an IOU, but the transaction was blocked by APUC even though the overall impact would have been to lower rates for all parties. Golden Valley Electric Association, the Fairbanks cooperative, is attempting to buy out Fairbanks Municipal Utilities, a municipal owned electric utility (subject to review and approval by APUC).
7. *What is the major difference between electric utilities in Alaska taking into account both urban and rural areas as compared to the lower 49 states?*
 - The biggest difference is the lack of an adequate transmission line system to allow full choice. A second major difference is the lack of choices. Finally, we are already a consumer owned utility state whose primary objective is reliable, affordable power as opposed to profitable power for the utility. As mentioned earlier, the ratio of consumer owned utilities to investor owned utilities in Alaska is roughly 9:1. This is almost a mirror image of the situation in the Lower 48 states. Furthermore, the transmission grid system in the Lower 48 states is highly developed and reaches virtually all communities and business sectors through a myriad of puths. This means that there are numerous utility choices available to consumers. In Alaska, we have a very rudimentary transmission line

system in the Railbelt area and virtually no interconnection in rural Alaska. Exacerbating the inability to move power around the State of Alaska is the absence of the multitude of providers available in the Lower 48 states. Unlike the telecommunications industry, investment in power generation is extremely capital intensive. For that reason, there is rarely little more than one entity that is interested in bringing power to an entire village or community. However, to ensure that even that single utility would invest the requisite capital to provide for a community, exclusive service areas were granted through the jurisdiction of APUC.

8. *Is there any state or states that have a similar electrical utility distribution system?*

- No. And interestingly enough, deregulation could result in an even more backward and less developed system than we presently have. For instance, if deregulation comes to the Railbelt, each utility will need to evaluate their individual transmission line needs. Presently, as you know, Chugach is considering extension of the southern transmission line to Soldotna, while Fairbanks is looking to expand the transmission line from Healy to Fairbanks. The State has put up grant funding for each of these projects, but neither amount is sufficient to fully fund either of the transmission lines. Thus the utilities will need to finance the balance of each project using debt capital. Certainly Copper Valley Electric didn't want to take on any more debt to complete the financing of the Sutton to Glennallen transmission line for which the State has made \$35 million available. In order to remain competitive, utilities under deregulation will shun taking on any more new debt that may affect their competitive edge. Thus, it may not come as a surprise if there is a decision to discontinue pursuit of at least one of these Railbelt transmission lines in anticipation of deregulation. The result may well be a loss of overall transmission lines available in the Railbelt to facilitate the very competition that is being sought. Reliability would suffer throughout the Railbelt, and the ability to transfer economical energy from one service area to the next would be diminished. The same may also happen to reserve generation capacity. Utilities will only be building to serve immediate customers and will not invest in the reserve capacity that the industry now expects. In fact this may become a major threat to the entire Lower 48 system under deregulation. Cost cutting measures will result in a diminution of the reserve capacity that makes the system reliable. And putting reliability issues aside, what is the cost to the economy from more frequent power outages? Perhaps the only thing saving the system will be the off peak demands artificially created by the changing time zones.

9. *If the ultimate goal is to lower consumer prices for electricity, is it true that deregulation and competition will be the method?*

- You're asking for a subjective evaluation here. As you know, even Congress is having second thoughts about deregulation of the electric utility industry. While I am a free market person myself, I have serious reservations about a totally deregulated electric utility industry even for the Lower 48 states, let alone Alaska where we are already a largely consumer owned utility state with a relatively uninterconnected utility system. I think that in Alaska, deregulation will just shift the benefits and burdens from one user class to the next, but the average cost of all electricity will remain little changed. The winners will be businesses with enough economic clout to force a lowering of their rates. The losers will be the small residential customers. Winners will also include small upstart dispersed generation providers that will be able to "cherry pick" the best customers in a given service area while the utility shoulders the responsibility of maintaining a grid system and backup generation required of them by their ever-increasing disgruntled member owners, and the APUC.

10. How should the state assure that residential consumers reap the same benefits as large commercial customers and how do we solve the rural/urban problems?

- There is no easy answer here. When one segment of the market has the ability to skew the pricing structure, another segment will have to pick up the slack. Certainly we have attempted to address this situation in HB-235. Deregulation may have a particularly regressive affect in rural Alaska where "cherry picking" could become a fruitfully common event. My own personal belief is that we can gain the greatest economy of scale in rural Alaska if we bring all of the smaller utilities under one master utility such as AVEC which presently provides service to some fifty or more villages. At the same time, the administration should issue a policy stating that any state or federally funded entity in village Alaska shall remain with the utility in the village and that any dispersed generation brought to a village should be administered through the local utility. This would allow small energy providers to come to rural Alaska, but coordinate their efforts through the local utility. In urban Alaska where we have more of a market economy and a bit of an integrated system, this plan probably wouldn't work. Commercial customers already get a rate break in comparison to residential consumers in the Railbelt area. Under deregulation, they would be able to get an even-greater price break; perhaps even greater than would be economically justified. Other ways to insure that rates in both rural and urban areas would not see too much rate shock under deregulation would be for the state to: (1) make provision for utilities to recapture revenue to pay for "stranded costs," (or for the state to pick up that cost since it is changing the rules under which the utilities were led to operate under APUC regulation), (2) have the state pick up the added cost of APUC increased regulation, (3) have the state eliminate the "obligation to serve" within a service area.

11. Can the state control the level of "cherry picking or cream-skimming" and accomplish increased competition at the same time without eliminating competition?

- This could probably be accomplished by vesting APUC with the authority to "control" all aspects of the industry. In so doing, APUC could establish some sort of criteria that allows "cherry picking" up to a point when rates for everyone else reaches a ceiling. It would then stop the practice until the market rates drop back down below a predetermined threshold. Essentially this is what is being attempted under HB-235. The debate is over the threshold.

12. How should the practice of "cherry picking and cream skimming" be defined?

- Cherry picking occurs when a competitor proposes to serve a customer outside of their own service territory at a rate that is less than the tariff approved by the APUC for that service territory. Under deregulation, service territories would eventually go away, and rates would be continually changing. Eventually consolidations would take place and competition would be eliminated. Cherry picking will have become subsumed by the overall practice of cherry picking.

13. When electrical service areas overlap how do we preserve competition without duplication of capital investment?

- This is an excellent question. At the present time there are no overlapping service territories. (The one exception is Klawock, and that is being ruled on by APUC at the present time.) History would indicate that duplication of effort will take place under an unregulated utility environment. APUC was required by the Legislature in 1973 to provide all of the utilities in Alaska with exclusive territories. Before that, however, it was a common practice to see two sets of distribution lines running down each side of the streets in Anchorage, for instance, as the two utilities vied for customers in a specific geographic area. But the basic answer to the question is, there will be duplicate capital investment by dispersed generation providers, and by the utilities themselves to some extent (in order to provide for customer choice and to compete with the independent dispersed generation providers). If on the other hand the utilities were only competing among themselves, there would be little if any new investment in generation as the utilities would not want to take on the new debt and become less competitive.

14. Should the APUC statutes be changed to include timelines for all of its decisions? Or should the statutes just establish a priority system for the commission?

- Frankly, the timeliness of decisions from APUC is so bad now that both the electric and telephone industries are considering asking the legislature to change their statutes to require that they act within prescribed time lines. Under deregulation of the electric industry, their workload will become even heavier.

15. What is the status of the Copper Valley "cherry picking or cream skimming" problem?

- Alaska Power Systems, which has recently received a \$1.5 million state grant to supplement their earlier state grants, has signed up two customers in the Glennallen area, is pursuing the school, and is still pressing for customers in the Valdez area. Copper Valley appealed to APUC for help, but APUC told them to come in with a legal docket request before APUC would consider the situation. That 160-page formal complaint was submitted to APUC on October 7, 1997.

I hope that our responses have been helpful. Please call upon me if I can provide additional information.

Sincerely,



Eric P. Yould
Executive Director

cc: Ken Lancaster
Larry Markley

att.

Attachment 1

Pres/GM	Title	Contact FirstName	LastName	JobTitle	Company	Address1	City	State	ZIP	Phone	Fax
Mr. Corbus	Mr.	William	Corbus	President	Alaska Electric Light & Power Co.	5601 Tonsgard Court	Juneau	AK	99801	907-780-2222	907-463-3304
Mr. Grimm	Mr.	Robert	Grimm	President	Alaska Power & Telephone Co.	P.O. Box 222	Port Townsend	WA	98368	360-385-1733	360-385-5177
Mr. Curtis	Mr.	Helvi	Sandvik	V.P. Operations	Artic Utilities, Inc.	1001 E. Benson Blvd.	Anchorage	AK	99508	265-4100	265-4123
Mr. Eggen	Mr.	Andrew	Eggen	General Manager	Haines Light & Power Inc.	P.O. Box 30	Haines	AK	99827	907-766-2331	907-766-2384
Mr. Eller	Mr.	Don	Eller	General Manager	Tanana Power Company	P.O. Box 873509	Wasilla	AK	99687	907-373-5599	907-373-5599
Mr. Manns	Mr.	Carl	Danielson		Bettles Light & Power, Inc.	P.O. Box 222	Port Townsend	WA	98368	360-385-1733	360-385-5177
Mr. Hanson	Mr.	Ed	Lockhart		Manley Utility Company, Inc.	5450 A Street	Anchorage	AK	99518	561-1674	563-3185
Mr. Linke	Mr.	James	Davenport		Alaska Power Company	2770 Sherwood Ln, Suite 213	Juneau	AK	99801	907-586-7405	907-586-7270
	Mr.	Daniel	Nelson		Napakiak Ircinraq Power Co.	P.O. Box 34030	Napaskiak	AK	99634	907-589-2227	907-589-2412
Mr. Brown	Mr.	Stanley	Brown	General Manager	Paxson Lodge, Inc.	Box 101	Paxson	AK	99737	907-822-3330	
Mr. Leonard	Ms.	Diana	Leonard		Egegik Light & Power Co.	Box 179	Egegik	AK	99579	907-233-2244	907-233-2213
Mr. Mickelson	Mr.	Carl	Danielson		Coffman Cove Electric Utility	P.O. Box 222	Port Townsend	WA	98368	360-385-1733	360-385-5177
Mr. Mager	Mr.	Jack	Mager		Sand Point Electric, Inc.	P.O. Box 209	Sandpoint	AK	99661	907-383-4020	907-383-5320
Mr. Tilbury	Mr.	Tom	Sterrett		Bethel Utilities Corporation	3380 C Street, Suite 210	Anchorage	AK	99503	562-2500	562-2502
Mr. DeMandel	Ms.	Darlene	Holmberg		Aniak Light & Power Co., Inc.	4th & Boundary Avenue	Aniak	AK	99557	907-675-4334	907-675-4334
Mr. Mahon	Mr.	Carl	Danielson		Northway Power & Light	P.O. Box 222	Port Townsend	WA	98368	360-385-1733	360-385-5177
Mr. Whitmarsh	Mr.	Glen	Woods		Pelican Utility Company	P.O. Box 110	Pelican	AK	99832	907-735-2204	907-735-2281
Mr. Helmer	Mr.	Carl	Danielson		Eagle Power Company, Inc.	P.O. Box 222	Port Townsend	WA	99368	360-385-1733	360-385-5177
Mr. Finnesand	Mr.	Martin	Finnesand		Chitna Electric Inc.	P.O. Box 88	Chitna	AK	99566	907-823-2220	
Mr. Kimberlin	Mr.	Ray	Kimberlin		Far North Utilities	P.O. Box 80564	Fairbanks	AK	99708	907-456-4201	907-456-2084
	Mr.	Robert	Enoch		Tuntutuliak Community Service	c/o General Delivery	Tuntutuliak	AK	99680	907-256-2529	907-256-2934
Mr. Ferguson	Mr.	Gary	Ferguson	General Manager	G & K, Inc.	P.O. Box 117	Cold Bay	AK	99571-0117	907-532-2407	907-532-2513
	Mr.	David	Thomas	Power Plant Operator	Gwitchyaa Zhee Utility Company	P.O. Box 09	Fort Yukon	AK	99740	907-662-2322	907-662-2983
Mr. Blodgett	Mr.	Don	Petersen		Teller Power Company	3301 Denali St.	Anchorage	AK	99503	278-8878	278-5779

POWER

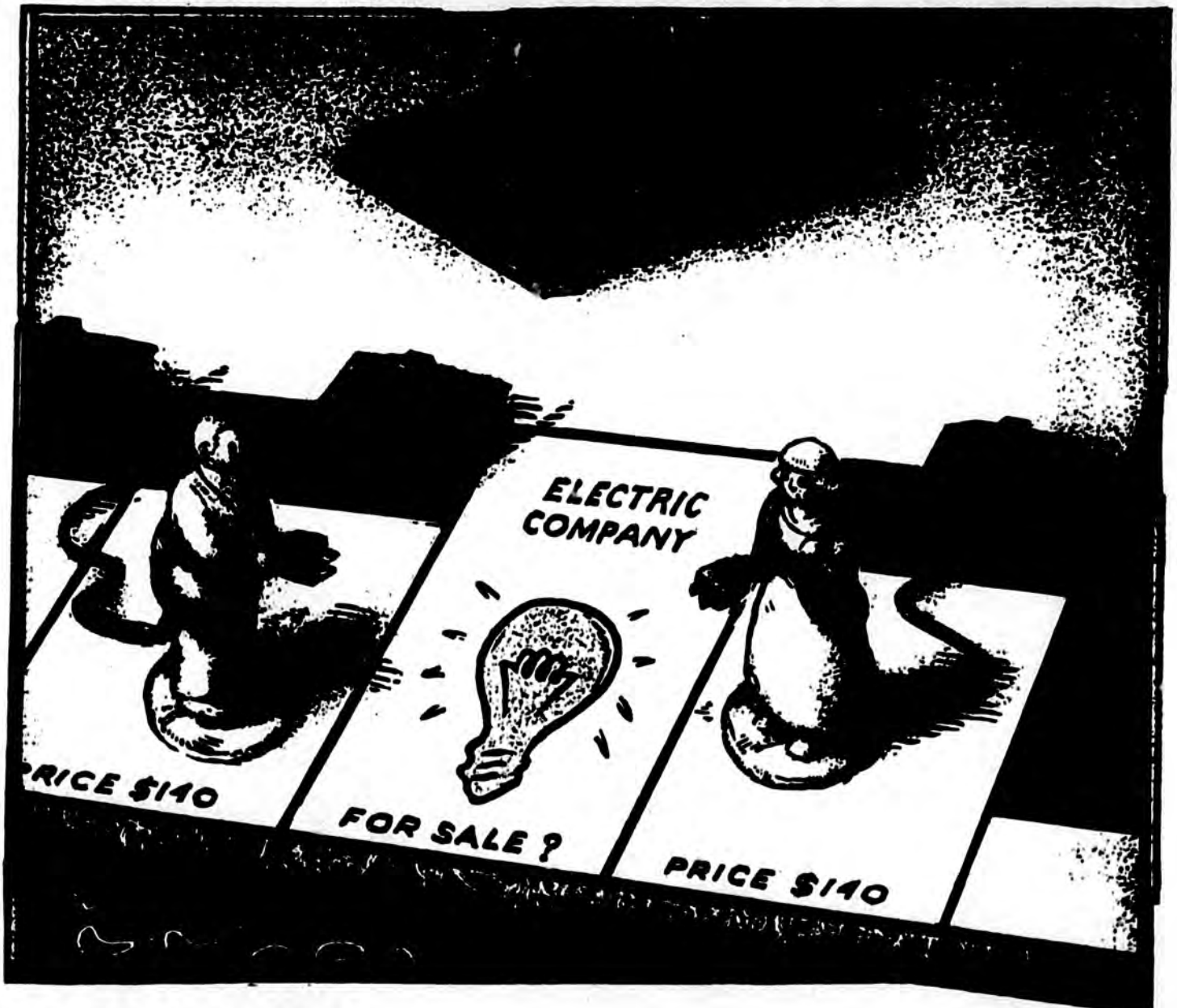
IF YOUR CITY OWNS ITS ELECTRIC utility, chances are there is some talk these days about selling it. The starting point for such conversations is nearly always the topic of electricity deregulation—and the big question that it raises in local officials' minds: Can we compete when our monopoly is gone? But regardless of whether the issue is debated loudly in the

public arena or discussed quietly behind closed City Hall doors, the deliberations all end the same way: without a sale.

Nobody knows this better than Tallahassee Mayor Scott Maddox and Memphis Mayor Willie Herenton. During the past year, they were the ones who initiated the discourse on privatizing public power in their respective communities. Both

mayors expressed concern about the possible impact of competition, and reasoned that a utility sale would absolve their cities of the risks of deregulation. In addition, money from a sale, socked away in a trust fund, could provide a steady revenue stream for years to come.

But like every other sizable municipality that has gone down this road lately, Tal-



POLITICS

lahassee and Memphis eventually turned back. Deregulation may be coming—and in some states it's already here—but city after city is deciding to compete rather than sell out. The interesting thing, in looking at Tallahassee and Memphis, is that deregulation stands to impact the two cities in drastically different ways. Yet both places ultimately concluded it was better not to sell. It seems that while the economics of selling utilities varies widely from place to place, the political roadblocks are the same everywhere.

Indeed, in the brave new world of competition, Tallahassee has everything to lose economically. The city is wedded to its utility revenues, which make up \$32 million of the city's \$100 million budget. That dependence comes largely from the city's status as a state capital. Between the government presence and that of two universities, Tallahassee cannot tax 53 percent of its land. The city charges relatively high electricity rates to compensate, but under deregulation, those same high rates could push big customers to bolt for better deals in the open market. And that, in turn, would further imperil the city's budget.

Memphis, meanwhile, is in a better economic situation. The city collects only \$20 million of its \$335 million budget from its utility. The city's electricity rates are among the nation's lowest. And unlike Tallahassee, Memphis is a distribution-only utility, meaning it owns only the poles and wires. That relieves Memphis of another layer of risk, since under deregulation, it is only the generation side of the business where monopolies are expected to get busted up. Still, the prospect of a windfall approaching \$1 billion has sparked more than a little interest among local officials in exploring a sale.

Of course, at this point, all of this local talk of competitiveness, risk and losing customers is only speculation. Neither Florida nor Tennessee has deregulated its electricity market, and neither is expected to for at least a couple of years. The world around the two states, however, is chang-

ing rapidly. Eighteen states have enacted deregulation plans and are at varying stages of implementing them. Thirty other states are debating or investigating deregulation. The idea of breaking up local electricity monopolies and letting customers choose their electricity provider offers the seductive promise of lower rates.

For the country's 2,000 municipally

Selling off the electric utility may make economic sense in this era of deregulation. But almost everywhere, public sentiment gets in the way.

■ CHRISTOPHER SWOPE

owned electric utilities, however, deregulation—or at least the prospect of it—is inspiring some major soul-searching. Every utility is different, and depending on whom you ask, the years ahead are laced with either opportunity or apprehension. It is this uncertainty that is causing a lot of municipalities to reconsider their role in the electricity business. Selling out is not the only possible approach, however. "This is a time when people are looking at their options," says Deborah Penn, a privatization expert with the American Public Power Association. "That includes changing the way you operate now or adding new services. Some would include the alternative of not staying in business."

In fact, many cities are examining a variety of possibilities, and in some that do not have public power, there is even a counter-

trend: A few towns served by private "investor-owned" utilities are looking at municipalizing those companies, Penn notes. But the list of places that have recently pondered a sale—Lansing, Michigan, Austin, Texas, and Riverside, California, to name a few—is evidence that the privatization idea is being taken very seriously. In countless other localities, officials are no doubt beginning to mull it over. "We should do that," says Barry Moline, head of the Florida Municipal Electric Association. "That's public power. We have an obligation to continually examine that option from time to time."

From the start in Tallahassee, to sell or not to sell was a question with a deadline. At the end of this month, the city is slated to start work on a new power plant. If a sale to a private entity were to happen, it had to occur before any tax-exempt municipal bonds were approved to pay for the \$109 million project.

Well aware of their budget's addiction to electricity revenues, and with the prospect of deregulation around the corner, city officials know that the price of inaction could be devastating. The utility's high rates make it a sitting duck for potential competitors. For example, one of its two biggest customers, Florida State University, is already talking of shopping around if the market opens up.

But Mayor Maddox sees another, more immediate impact from the deregulation already taking place in other states. Among investor-owned utilities, deregulation has unleashed a spree of buying, selling and merging. The companies are looking for economies of scale and to make inroads into new markets, and in many recent cases, they are paying a pretty penny for the privilege. For example, one privately owned utility in Tallahassee's backyard, Florida Power & Light, recently paid an exorbitant \$846 million for another private utility's power plants in Maine. Maddox figured it was a sellers' market and wondered if Tallahassee's utility



Mayor Scott Maddox proposed soliciting bids on Tallahassee's electric utility. But his plan was nixed by the rest of the city commission.

might fetch the same premium. "Several national companies want a foothold in Florida," he says. "And Florida's investor-owned utilities will pay to keep those folks out."

The question of value, and whether it would increase or decrease under deregulation, is a contentious one. Maddox believes that if competition comes and there's a municipal utility fire sale across Florida, the selling price will go down. The value may further decrease if Tallahassee loses its biggest customers.

Others say that if Tallahassee can get its rates competitive, it has nothing to worry about. The area's population is growing, and that should help buffer any lost customers. What's more, they add, the biggest source of future value to the utility is its connection to its 90,000 customers. The poles and wires and rights of way the city owns are essential if the city should decide some day to jump into other businesses, such as telecommunications or cable television.

Currently, the utility's value is believed to lie somewhere in a broad range between \$300 million and \$800 million. But the one sure way to find out what private utilities would pay is to ask. So last winter, Maddox proposed to seek bids, and if any especially juicy offers rolled in, the wheels of a sale could be put in motion.

That, however, is when the political reality of a sale hit. Three city commissioners (a majority) lined up against Maddox, saying the sale option was being pushed too hard and too fast. They believed major concerns—losing local control of the utility, the fate of its 300 workers under private management, and pure sentimentality for an institution as old as electricity itself—were being steamrolled in the deadline rush. The mayor's advisers said that the utility could sell

without going before voters, and many folks found that frightening. "People said, 'We love our electric utility, so don't move too quickly on this,'" recalls Commissioner Deborah Lightsey, a leading sale opponent.

In short, Maddox underestimated the intense feelings residents had about public power. Chief among those is local control: People like the idea that elected local officials essentially act as the utility's board of directors. When the lights go out, a customer can call not just a power outage hotline but also their city commissioner to complain. That would disappear under private ownership. Moreover, as is often the case with public power, the city utility has a good track record with customers. By one common measure—outage rates—Tallahassee's service is four times better than Florida's major investor-owned utilities.

All along, however, the mayor and his advisers viewed a sale not so much in terms of electricity service but in terms of dollars. The sale idea, he says, came about at a strategic planning meeting. "I asked, 'Why are we in the electricity business? Is it to provide electricity? To preserve energy? Or is it for the money?' Everyone agreed it was for generating revenue." If a private suitor was willing to pony up three times the book value, they figured, it would outweigh the local-control concern. Money from a sale could be put into a trust fund and the city could ride into the deregulation sunset living off the interest.

Of course, there was no guarantee a bid would come in at all, let alone an exceptionally high one. For example, Anaheim, California, solicited bids on its utility last year. Anaheim was willing to entertain just about any type of bid, be it an outright offer to buy, to form an alliance with

another utility or to outsource certain operations. It was a fishing expedition, and Anaheim wanted to see what it could catch. The city got 21 bites—all alliance and outsourcing proposals—but nobody was seriously interested in a purchase.

In Tallahassee, however, when it came time to go fishing for offers, the commission punched a hole in the boat. Rather than soliciting bids, commissioners voted 3-2 to investigate options other than a sale. With momentum behind the sale option dead, the boat then sank. The vote on financing the new power plant succeeded 4-1, effectively killing the sale option. Maddox' vote was the only "nay."

The mayor's advisers couldn't help but wonder if the result would have been different if it were a private, rather than public, utility being unloaded. They believed the financial calculus favored a sale. But the protracted public debate that was required once selling became a serious consideration allowed time for opposition to galvanize. "We were clearly handicapped by the requirement to operate under public meetings laws," says City Attorney James English. "The board of directors meetings of our future competitors aren't on live TV."

Memphis officials knew from the very beginning that putting the utility on the block would be a tough sell. Memphis Light, Gas & Water Division is widely respected and considered a model operation among utility experts. Perhaps more important, the company is known for its tradition of giving back to the community in a variety of ways, such as setting up special weekend classes for students of inner-city schools. Given community sentiment about MLG&W, it was clear that doing anything drastic to the utility would require broad political support.

Nevertheless, Mayor Willie Herenton suggested last winter that the city consider selling MLG&W. Like Maddox, he argued that deregulation made it a good time to examine future options for the utility. And in this market, buyers might pay a mint, especially for a well-run utility such as MLG&W. "This is a historic opportunity in the market to do something," says Michael Harris, a managing director at Morgan Keegan & Co., a local investment firm that studied a MLG&W sale. "The key to valuation is the stock market and interest rates. The timing is great."

While the market may be ripe, there was significant doubt about the deregulation

question. Certainly, compared with cities such as Tallahassee, Memphis is well positioned for when the deregulation train rolls into town. Memphis' electricity rates are more competitive, making it less likely to lose big customers. The city's budget is less dependent on utility revenues, and MLG&W already has some experience with deregulation in the market for natural gas. But most important, unlike Tallahassee and a lot of other municipal utilities, MLG&W owns no power plants. That means Memphis won't be subject to the dog-eat-dog competition in the generation side of business, where analysts say the most money will be made and lost.

However, deregulation does pose some risks for MLG&W, mostly inherited from its electricity supplier, the Tennessee Valley Authority. Since TVA's creation in the 1930s, the federal agency has been providing MLG&W and other municipal utilities in the region with cheap power from its vast network of dams and power plants. Memphis, in fact, is TVA's biggest customer. Theoretically, if Congress were to pass deregulation nationally and include TVA, distribution-only municipals like MLG&W could shop for even better deals from other providers. The problem is that TVA's contract locks them in: If Memphis wanted to shop around, it would have to wait a full decade.

The TVA contract, which Herenton describes as "onerous" and "distasteful," is an albatross for another reason. TVA currently carries an enormous \$27 billion debt on its expensive generating facilities. If Congress doesn't significantly bail TVA out of those stranded costs, TVA may have to raise the rates it charges distributors such as MLG&W. That could ripple through to the rates MLG&W charges its customers, making the utility less competitive in the long run. "We're at the mercy of TVA," Herenton says, "Their rates drive our rates."

Still, it was apparent that money, in addition to deregulation, was a driving force behind the sale idea. Morgan Keegan had been pitching the idea of a sale to Herenton for years, arguing that MLG&W was a cash cow waiting to be milked. The firm had conservatively estimated MLG&W's worth at between \$600 million and \$800 million, and other estimates topped \$1 billion. The money, if put in a trust fund, could bring in \$70 million a year in interest.

Mayor Herenton and his staff touted a



Sale opponents complained that Memphis Mayor Willie Herenton had pre-ordained MLG&W's fate.

litany of ways the cash could be spent: pay down the city's debt; hire 200 new teachers and 400 new police officers; get new computer systems for schools and police; provide free trash collection and slash property taxes. Herenton says he looked at the situation as a business would. "I don't know any corporation that would have an asset like the city of Memphis has on its books and not try to secure a bigger dividend from that asset," he says.

To opponents, however, the trust fund wish list showed Herenton's bias toward a sale. The mayor maintained he wanted only to study options for MLG&W, but he was already talking up how to spend the sale money. "If I felt his proposal was about studying the potential of changing the status of MLG&W, then I would've supported him 100 percent," says Councilwoman Pat Vander Schaaf. "But he leapt to those figures and into a different dimension completely."

To be sure, the windfall sounded great, but most residents were leery of the cost. MLG&W is Memphis' most valuable asset. Once it is gone, it would be very difficult for Memphis to get it back. And while the city would have these fat trust funds in its stead, what would keep politicians from dipping into the principal and frittering the funds away?

There were other concerns as well: Would the utility's new corporate owners, with headquarters perhaps thousands of miles from Memphis, give as much back to the community as the old MLG&W had? As to the city's low electricity rates, nearly everyone expected those to go up. After all, new owners would be concerned with mak-

ing a profit, not with providing the lowest-cost service possible. And what about the utility's 2,600 employees? Would some of them be laid off under private ownership? The questions produced enough anxiety that some 74 percent of those polled by a local newspaper, the *Commercial Appeal*, said they opposed the sale.

Herenton, like Maddox in Tallahassee, suggested a possible end-run around the opposition. He found a loophole in the law that could allow a sale without getting the consent of voters. The idea, not surprisingly, was a lightning rod for his adversaries. They claimed it was further proof that the mayor had pre-ordained MLG&W's fate, although Herenton insists he was merely laying all available options on the table.

In the end, however, no vote was necessary. At the same time Vander Schaaf was building city council support to pull the plug on any sale, the mayor's own consultant, Rotan Lee, weighed in with a recommendation against selling. Lee's reasons were somewhat diffuse; he said the utility did not provide him with certain information he needed. His report, however, acknowledged the political pitfalls of pursuing a sale. "Fears of rate increases, loss or replacement of a trusted provider and disruption of the status quo are common and natural," Lee wrote. "Freedom of choice does not automatically supplant the belief that government is a better guardian of the public's interest."

Indeed, perhaps the single greatest political force lined up against the likes of Herenton and Maddox is inertia. "There's a lesson to be learned here," says state Senator Jim Kyle, a Memphis Democrat working on deregulation issues. "It's that when we have a government entity that has the public's confidence, the public as a whole is not interested in change."

Nevertheless, there is widespread agreement in these two cities that as the era of electric deregulation draws closer, the subject of selling off the public utility will be revisited. Florida and Tennessee are only beginning to consider deregulation, and when the time finally arrives to compete—two, four or six years from now—the jitters will no doubt kick in again. "This whole debate is just beginning," says Memphis City Attorney Robert Spence. "I would be surprised if what we decided this spring is the final word." ■

An Electrifying Breakthrough



THIS SPRING, the obscure Pennsylvania-New Jersey-Maryland Interconnection Association, known as PJM, changed the prices it charges to use its power lines. In doing so, it put in place an infrastructure policy so significant that Kennedy School of Government Professor William Hogan, a leading scholar on utility deregulation, describes it as a "major breakthrough" needed to ensure the success of electricity deregulation in several states.

To get a handle on the innovation, it helps to understand how deregulation evolved. In other critical industries, such as telecommunications, aviation and natural gas, services were provided by privately owned companies but regulated by governments as monopolies. Through much of this century, this system worked well. In the 1970s and '80s, however, fuel prices and power-plant construction costs increased dramatically, creating a concern that utilities were being rewarded for making investments, rather than for being efficient. At about the same time, scholars challenged the idea that many regulated industries were natural monopolies.

In the economic doldrums of the times, these ideas resonated. In less than a decade, deregulation swept aside laws governing airlines, railroads, trucking firms, natural gas and telecommunications. Now, the federal government and several states—notably Massachusetts and California—are opening electricity to competition as well.

In pursuing these policies, states and the federal government have followed a model used in natural gas deregulation and telecommunications. Specifically, they are encouraging competition in generation, where it is feasible, while retaining monopolies in transmission lines, where competition is impossible. Doing so requires setting prices for transmission, which in natural gas lines is a relatively straightforward question of calculating existing capacity and the cost of adding additional transmission lines.

It turns out, however, that the physics of power lines make it difficult to follow this approach in electricity because the capacity of the whole system is not fixed. Instead, it varies depending on where power enters the system, where it leaves and the capacity of the lines in between those points. It is possible, for instance, to add 1,000 megawatts from one power plant without creating any problems, while adding the same amount of power at another location could overtax the system.

Historically, when demand for electricity approached the

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transmission system's capacity, consortia of utilities, known as regional power pools, found the combination of power plants that could meet total system demand at the lowest total cost. This approach, however, is not compatible with a deregulated system that allows individual generators to contract with individual consumers for the sale and delivery of power.

One solution, favored by many firms trying to take advantage of utility deregulation, is to give all sellers and buyers unfettered access to the system and set transmission fees at their average cost. This approach, however, could wreak havoc. If deregulated power producers add power at congested spots in the system, the system operator would have to shut down power plants in other locales. This, in turn, could drive up costs for other users or disrupt other direct transactions between buyers and sellers of electricity.

That's where PJM's new pricing system comes in. Last year, PJM, a regional power pool serving mid-Atlantic states, won permission from federal regulators to base transmission fees on the hourly cost of adding power at different points near one or more major power plants—even though some independent power producers feared that the system would lead to higher transmission costs that would make them uncompetitive.

PJM started using the system in April and, contrary to the predictions of those who touted average cost pricing, the difference in costs between various locations has been substan-

A new way of pricing power-line charges is critical to ensuring the success of electric utility deregulation.

tial. When the demand for power is close to the system's capacity, for example, charges for access to the electric lines can range from about \$90 per megawatt hour to a negative \$10 dollars a megawatt hour. (The negative number is because in some cases, adding power at certain points actually increases overall system capacity.) In an industry where price differences of a few dollars a megawatt hour are significant, such cost differences are enormous. It is no surprise, therefore, that the power pool serving New York State is about to implement a similar system and other power pools are considering it.

Ultimately, the PJM story is important in two ways. It is a critical element in ensuring the success of utility deregulation, and it shows that as regulators and policy makers move to bring market-based reforms to fields that range from the sale of water rights to opening local telephone markets to competition, they must be careful to design systems that reflect both underlying economic principles and the physical characteristics of the networks that deliver critical services. ■

Power Business



MICHAEL L. AMMONSON

The bloated, 120-year-old electric power industry isn't just being deregulated—it's being revolutionized. The impact on business will be huge.

BY BRIAN O'REILL

It seems so incredibly obvious you want to slap your forehead for being so obtuse all these years. Electric power costs a bundle in places like New York and California but barely a third as much in out-of-the-way states like Idaho, West Virginia, and Kentucky. *Why not take all that cheap power the West Virginians aren't using and ship it to Manhattan, Chicago, San Francisco?*

That, vastly oversimplified, is the idea behind the move to deregulate the electric power industry: If your power company is charging too much for electricity, why should you be forced to accept it? Why can't you shop around? Why can't a power company from Pocatello knock on your door and offer a bargain kilowatt or two?

It's coming. There will be far more competition in the electric power business. It is reasonable to expect that deregulation will cause the nation's \$212 billion-a-year electric bill to drop by 20% to 30% or more in the next five to ten years. But not before a vast tangle of technical, economic, and political problems gets solved.

If it works, and it should, the consequences will be enormous. "Electric power is the biggest American industry ever to be deregulated," says Kenneth Lay, chief executive of Enron, a big, aggressive gas and electricity marketer that has led the drive for deregulation. "It's about twice the

size of the long-distance telephone business and dwarfs the gas, airline, trucking, and railroad industries, which were all once regulated." The average homeowner, who uses about \$850 worth of power a year, won't be financing trips to Bermuda with the impending savings. But the potential savings for business are huge: Electricity can account for more than 15% of operating costs for a big company such as Chevron, which spends about \$250 million a year for power in the U.S. Lay notes that industrial and commercial companies consume about 60% of all power sold.

"The billions they stand to save will boost corporate profits and make American companies more competitive internationally," he says. (The upheaval in this once-staid industry will hit investors too: Owning utility stocks isn't just a matter of waiting for dividend checks anymore. For a look at how electricity deregulation affects the market, see *Personal Fortune*.)

All this is small comfort for the big, often bloated electric utilities, which have lived a long, comfortable existence as regulated monopolies. Already the prospect of deregulation is prompting much moaning and groaning, and with good reason: Deregulation will force many utilities to become far smaller. They will have to sell off some or all of their brawnier assets—those massive generating plants—and make a living mostly by operating the wires that run to homes and factories.

BUT WHAT ABOUT GRANNY?

Naturally, utilities are piously declaring that they relish the bracing winds of competition. But with barely a pause, they urge caution, hinting darkly at the havoc any rapid move will bring to this complicated, delicate industry: grandmothers stuck in elevators, hucksters who won't deliver the juice you need on a hot night, novice power plant owners frying transmission lines as they greedily try to ship power to places that can't handle the load.

If the electric power industry is doomed to collapse in a shower of sparks, we'll find

out soon enough. Regulators in California defied the Cassandra and declared that everybody can buy power from anybody, starting next January. Already advance men from all over the country have

descended on the state. None seem particularly worried they'll be stuck in elevators.

If anything, the electric business will run better than before, says Michael Peevey, former president of Southern California Edison, one of the biggest utilities in the country. Under the existing scheme, electric companies go virtually unpunished for power failures, Pee-

vey says, so power outages are far from rare. But Peevey noticed that when a Cal Edison subsidiary built and operated power plants for private customers and was penalized for down time, the plants ran smoothly 95% to 97% of the time—considerably better than Cal's regulated plants. "That's when I began to have creeping doubts about the wisdom of regulation," says Peevey. "I was like a fallen Catholic. I no longer believed." He quit and now runs New Energy Ventures in Los Angeles, which plans to help companies buy inexpensive power.

A QUIRKY INDUSTRY—REALLY

Not that anybody really knows how all this deregulation will work out. For all its apparent blandness, this is, believe it or not, a varied, quirky industry. Unlike the old Ma Bell, which seemed to spawn seven clones of itself at breakup time in 1984, each of the nation's 198 investor-owned utilities seems markedly different from the others in operations, culture, oddball problems, and long-range financial prospects.

How different? Ohio-based American Electric Power runs gigantic power plants right near coal mines in Ohio, West Vir-

ginia, and Kentucky, with boilers so vast they can fit the Statue of Liberty inside. Consolidated Edison in New York City has to run almost all its wires underground, at a cost eight times greater than stringing them on poles. Cinergy, an aggressive midsized utility in Cincinnati, is determined to be one of the five biggest energy traders in the country.

It's hard to say which private utilities will thrive. Each state will devise most of the rules governing the deregulation—and the fate—of its own utilities. In most states, though, regulators have barely begun to tackle deregulation. (The 3,000 or so electric cooperatives and government-owned utilities will be affected by the changes sweeping the industry, but they're exempt from deregulation.)

So in the absence of any simple declarations about the electric power business, herewith a guided tour of the problems, issues, and peculiarities of this soon-to-be-transformed industry.

LET'S REDECORATE!

One of the infuriating practices of most utilities has been their failure to economize. Why should they? Regulators routinely allowed them to earn a fixed rate of return on their assets. The result was a perversity known as "asset-based management." The more money a utility spent



Kenneth Lay, CEO of Enron, has led the fight for deregulation.

adding generators and other assets to its local power system, the more money the company made. Thus, for instance, cost overruns on nuke plants didn't cause too many sleepless nights for executives.



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TRICITY

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American Electric Power runs this huge, 1,300-megawatt power plant in West Virginia. It can ship cheap power all the way to New York City.

Michael Peevey says overruns on Cal Edison's nuclear plants "doubled our assets and doubled our earnings." (As the CEO of Wisconsin Power & Light, Erroll B. Davis Jr. once remarked, "This is the only business in the world where you can increase your profits by redecorating your office.") Such gold plating should stop as competition heats up in the industry, particularly with generating equipment.

"BUT WE HAD TO BUILD IT"

The great nightmare for many utilities is what to do with all their high-cost plants once competition begins. It's not a problem now, when every home and business in a power company's franchise area has to pay for the power regardless of price. But Con Edison has an old generating station in Manhattan that produces power at an absurdly expensive 11.7 cents per kilowatt-hour; other utilities run nuclear plants whose kilowatts cost almost as much. What will those plants be worth if someone else can make power for 3 cents and send it to New York? If a plant becomes worthless because competitors can undercut its costs, do Con Ed's stockholders eat the loss, or will Gothamites?

Sorting out which costs were truly wasteful and how to pay for the rest is a major hot potato for state legislators and regulators and will probably delay the full effect of deregulation for years. Rather than label these costs "the tab for our boneheaded overbuilding," utility execs conjured up the academic-sounding term "stranded costs." They tend to blame 1970s-era federal policymakers, who encouraged nuke plants after the Arab oil embargo.

The bonehead/stranded stakes are huge. Early estimates of the write-downs utilities will have to take when competition makes many of their assets and supply contracts uneconomic range from \$100 billion to \$400 billion. In August, California-based Pacific Gas & Electric surprised many observers by paying above book value for a handful of generating plants sold by a New England

utility. But that high price may be an anomaly: Problems at nearby power plants have caused a power shortage in New England, driving up the price PG&E can charge when it sells power to other utilities in the area. It's still not clear who'll pay what for old power plants as they come on the market, but Kit Konolige, an analyst at Morgan Stanley, says power generation assets may concentrate among a few huge companies.



THE VISIBLE, CLUMSY HAND

This won't come as a surprise, but in the past utility regulators occasionally goofed bigtime. About 20 years ago federal regulators mandated that certain kinds of new, private, unregulated generating companies (known as nonutility generators, or "NUGs") could sell their power to utilities. New York regulators foolishly

declared that its utilities had to accept power from anyone who charged 6 cents or less. Scores of sharpies quickly calculated they could make power for far less, and forced 20- and 40-year supply contracts on New York utilities.

Now, with power sometimes available on spot markets for just 2 cents, power companies are screaming bloody murder. Con Ed in New York says the contracts are costing customers \$530 million a year. Niagara Mohawk, an upstate power company, says the contracts nearly pushed it into bankruptcy. Before competition can begin in New York, utilities argue, they must be relieved of their overpriced contracts. As with uneconomic power plants, New Yorkers will be asked to pay up, probably through state-issued bonds; rate payers in California and other states can expect the same. It will cost billions.

REGULATION WAS OKAY ... ONCE

Regulating utilities wasn't always a dumb idea. By the late 1920s, 50 years after Edison invented the light bulb, the industry was a mess. Three big holding companies controlled half the power made in the U.S., and another 13 companies held an additional 25% market share. Often they were byzantine in complexity and dubious in ethics: Subsidiaries paid huge management fees to their parents, asset values were inflated by sales from one subsidiary to another, and companies often issued worthless stock. Many collapsed in the 1929 stock market crash. In 1935 Roosevelt stepped in, breaking up the multistate holding companies, limiting power companies to compact, contiguous service areas, and preventing unregulated companies from selling power. Hit by both the Depression and more effective regulation, average power prices, which peaked at 32 cents per kilowatt in 1932 (in 1992 dollars), declined steadily for more than 40 years before rising again.

A MARKET EXPLODES

Even now, if you think your local utility is charging too much for power, you have no choice but to pay for it. By law, nobody else is allowed to sell power to you. Frustrating, eh?

Utilities themselves had a similar problem. When utilities can't or don't want to generate all the power their customers

need, they often buy surplus power from other utilities. Problem was, the neighboring power company didn't have to sell. It didn't even have to transport power from a faraway utility if it didn't want to. So if a utility in, say, Tennessee, offered cheap electricity to a power-hungry utility in Florida, and asked a utility in Georgia to transport the electricity, the Georgia utility could refuse—and offer Florida its own, more expensive juice instead. All that began to change in 1992, when Congress ordered privately owned utilities to allow

"wheeling," or transporting power from one utility to another across a third's transmission system, if it had enough capacity.

And the market for wheeled power exploded. There is an oversupply of generating capacity in much of the country, but the complexity of shutting down and starting up a power plant means that many have to run constantly, even if customers are few. Therefore, lots of power gets dumped on the market for far less than the average cost of production.

Experienced commodity traders, notably Houston-based Enron, jumped into the act. Enron, formerly a regulated gas pipeline company, made a fortune when the pipeline industry was deregulated in the early 1980s. Because many big gas buyers are electric companies purchasing generator fuel, Enron already knew the players and the market.

Now Enron traders are on the phone 24 hours a day, calling up power plant operators to see who needs power, who's selling it, which transmission lines are at capacity. They can slice a gigawatt of power into pieces and sell the parts faster than an Omaha hog butcher. A utility needs a steady 50 megawatts per hour all day tomorrow? Sold. Need 400 megawatts of reserve capacity in case a generator goes down next week? Got it. All kinds of companies have joined the fray—utilities, Wall Street firms (see box)—but utility executives seem to be



More than 600,000 miles of high-voltage transmission lines crisscross the U.S. These carry cheap power from Oregon to California.

in particular awe of Enron, which now buys and sells more power than anybody.

TECHNICAL DIFFICULTIES

On a map it looks so straightforward. The cheap power is made over here, in coal country; the big city over there is paying a fortune for its power. Can't they send a bunch of econo-gigawatts from the Midwest to New York? Yes, but not easily. Electric utilities all over the country are interconnected. Alas for would-be marketers, this interconnectivity was designed as a way to back up neighboring utilities during emergencies, not as a way to move power easily over long distances. Electricity can't be routed to a particular place like a phone call, and a lot of power gets wasted as heat when it's transmitted over long distances. As a result, a lot of the anticipated price competition among generators won't develop until delivering power gets easier.

Think of all those big overhead transmission lines as a web of interconnected lakes and canals, not as a switched telephone network. Dump enough extra water in your lake, and eventually water levels rise for everybody. Usually.

Say Cinergy, in Cincinnati, agrees to sell extra power to the New York Power Pool (a confederation of interconnected utilities), which sees a heat wave coming. Cinergy starts making more power than its

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ELECTRICITY

own customers need. On paper, Cinergy's surplus power travels through Dayton Power & Light's wires, then on Ohio Edison's, then over Duquesne Light's, through the Penn-Jersey-Maryland (PJM) Power Pool's wires, and into New York. In reality, however, the power flows willy-nilly wherever it wants—usually over the path of least resistance (but sometimes on to a neighbor's already-full wires, causing them to overheat, and prompting a mad scramble by the neighbor to shut down generators and reroute power). Often, most of Cinergy's surplus power wanders into the lines owned by neighboring American Electric Power (AEP), whose turf extends toward Pennsylvania, eastern Ohio, and Virginia. The people at AEP, however, are displeased. Under current rules (no pun intended), Dayton Power and all those other utilities will collect a fee for carrying the load, even though most of it goes through AEP. "It's a pain in the neck," says E. Linn Draper Jr., AEP's CEO.

This is not a trivial problem. Since many utilities will have to sell their power plants and make money operating power lines, how will they be able to charge for wheeling a neighbor's power? Can they

charge extra at times of peak demand? No final decisions have been made.

\$32 MILLION PER MILE

If you think driving in New York City is tough, try delivering electrons there. Geography, history, and politics have made the place a power wheeler's nightmare. It sits at the bottom of funnel-shaped New York State, and all the upstate and out-of-state transmission lines that could bring cheap power must go underground at Yonkers, just north of the city, or run through tunnels under the Hudson and other rivers. So even if there are gigawatts of cheap power available elsewhere, little of it can make its way into the city. On a hot day, Con Edison needs 11,000 megawatts of power but can import only 4,500 and must generate the rest in the city.

That helps keep residential prices in New York City, now 16.2 cents per kilowatt, the second highest in the continental U.S., after nuke-beleaguered Long Island. Con Ed, like utilities in many big cities, can't burn cheap coal for environmental reasons and must use natural gas or low-sulfur oil. In addition, its generators are inefficient.

and it pays a ton in state and city taxes. Why not just build more transmission lines? "It's easier to get permission to build a new generating plant than a new transmission line," says Jack Feinstein, a Con Ed vice president. Cheaper too: Running a new 345,000-volt power line underground from Yonkers to midtown Manhattan would cost \$650 million, Feinstein says.

California has similar problems. Nearby states produce vast amounts of cheap power, but California has only two major links with outsiders: a tangle of wires coming down from Oregon and another link that runs from Arizona toward L.A. Only 12,000 of the 40,000 megawatts California needs during peak demand can come from out-of-state generators.

CALIFORNIA DIVES IN

On Jan. 1, Californians will be able to buy power from anybody who offers it. That puts California way ahead of almost all other states, which have, at best, allowed a few trial programs. But getting California utilities to sign on to the plan and drop threats of lawsuits required political horse-trading that exacted a high

The volume of power that utilities sell to one another has boomed. At LG&E in Louisville, traders buy cheap power on the spot market.

Need Electricity? Call Your Broker

Electricity is turning into a commodity, bought and sold like any other.

Soon you'll have *lots* of places to buy your power.

BY BETHANY McLEAN

TRADERS SWIVEL IN THEIR CHAIRS, EYEING THE PHONES and the flashing computer screens. Second by second, they monitor commodity prices and weather conditions across the country. Tension runs high: A slight delay could cost millions. Sounds just like ... Louisville? Here on the trading floor of the local utility, LG&E (Louisville Gas & Electric), they're not swapping stocks and bonds; they're swapping electricity.

The deregulation of the electric utility business isn't merely uprooting ancient monopolies—it's also creating a whole new industry: "power marketing," the buying and selling of electricity on the open market. In fact, this already huge, rapidly developing business may become the biggest commodity market in the country. Scott Spiewak of the Power Marketing Association (yes, there's already an industry association), says about \$50 billion of power is changing hands on trading floors. Within five years, he predicts, power marketing will be a \$2 trillion business. What's especially impressive is that this is an industry that didn't exist a few years ago. Only in 1992 was the wholesale market (i.e., sales of electricity from one utility to another) opened to competition; the biggest part of the business—selling electricity to businesses and homeowners—hasn't even been deregulated yet. In the first half of 1997, almost 380 million megawatt-hours were traded, six times the amount traded during the same period in 1996.

As weird as it sounds, trading electricity isn't much different from trading soybeans, oil, or pork bellies. There are electricity options and futures contracts, for example. As with traditional commodity markets, electricity traders try to lock in prices or speculate on price volatility.

One significant difference from more conventional markets, however, is that there's no real way to store electricity—and that helps make electricity trading a volatile business. And if weather sweeps in or a plant goes down unexpectedly, an immediate shortage may result. Because of these sudden, dramatic imbalances in supply and demand, the price of power can soar from \$20 to \$150 per megawatt-hour almost instantly. Tim O'Neill, a managing director at Goldman Sachs, says that in a fully deregulated market, electricity prices may be more than twice as volatile as the stock market, making electricity the most volatile commodity in existence.

Even though power marketing is still new, it's already transforming the famously stodgy utility culture. Utilities used to do business much like kindergartners—they shared. Now they find themselves wheeling, dealing, and generally acting like competitive businesses.

The biggest culture shock facing utilities has come in the form of a whole new set of big, mean players: Wall Street in-

stitutions. Commodity trading is Wall Street's turf, after all, and electricity is too rich an opportunity to ignore. The biggest power marketing deal to date—a supply agreement for Oglethorpe Power, a cooperative in Georgia—clearly shows that the Street has arrived. Last fall Oglethorpe signed a contract with utility LG&E; in March 1997 it signed a second contract with Morgan Stanley Dean Witter. Each will supply half the electricity Oglethorpe's customers consume—worth well over \$5 billion over the life of the contracts.

This raises a question: Will people buy electricity from fast talkers in very expensive clothing? Customers have to believe their supplier will deliver those electrons every day, which would seem to give an edge to utilities. Morgan Stanley traders certainly can't run power plants. "Power plants give them the wilies—might get their suits all dirty," jokes Robert Hosfeld, Oglethorpe Power's vice president of power marketing.

Then again, soybean traders in Chicago aren't farmers. Oglethorpe has full faith in the electricity-supply capabilities of Morgan Stanley, which won the contract over Enron, the big natural-gas company—and arguably the toughest, most sophisticated power-marketing player of all. Morgan buys and sells the equivalent of 20% of the world's energy products every day, and its executives have no doubt it can handle this electricity deal.

Whoever comes to dominate this new industry, power marketing is changing the way people think about electricity. There are about 300 companies—old-line utilities, gas companies like Enron, investment banks, and others—battling for a share of this business. Soon many of them will be coming after consumers to... Imagine dialing your Morgan Stanley Dean Witter branch and charging your electricity supply for the month to your Discover card. Your broker, your power company. How's that for change?



Power marketing in action