BEFORE THE
COUNCIL OF THE CITY OF NEW ORLEANS

Ex Parte Application of
New Orleans Public Service Inc.
Concerning a Least Cost Integrated
Resource Plan for New Orleans Public
Service Inc.

Docket No. UD-92-2a

and

Ex Parte Application
Of Louisiana Power & Light Company
Concerning a Least Cost Integrated
Resource Plan for Louisiana Power &
Light Company

Docket No. UD-92-2b

REBUTTAL TESTIMONY
OF
PAUL L. CHERNICK
ON BEHALF OF
THE ALLIANCE FOR AFFORDABLE ENERGY

Resource Insight, Inc.

March 10, 1995

TABLE OF CONTENTS

I. Introduction

Q: Are you the same Paul Chernick who filed direct testimony in this proceeding?

A: Yes.

Q: What is the purpose of your rebuttal testimony?

A: The purpose of my rebuttal testimony is to respond issues raised in the February 10, 1995 testimony of the Council's Advisors.

Q: Please summarize your response to the testimony of the Council's Advisors.

A: I concur with most aspects of the Advisors' testimony, including:

- finding that retail competition is not changing in any radical manner.
- recommending that the TRC test continue to be the dominant screening test for DSM.
- rejecting Entergy's proposed substitute for the IRP Ordinance.
- finding that the Ordinance currently allows for appropriate consideration of rate effects, load-building options, and confidential information.
- rejecting any revisions to the Ordinance at this time.

Notwithstanding this broad agreement on fundamental issues in this proceeding, I find that I disagree with a few of the Advisors' conclusions and recommendations.

Q: What issues will this testimony cover?

A: Specifically, I will respond to:

- The testimony of Mr. Corder, concluding that NOPSI will not receive full credit for DSM load reductions unless other Entergy subsidiaries participate in DSM.
- The testimony of Mr. Silkman and Mr. Vumbaco on screening tests, including the role of the Rate Impact Measure (RIM) Test, the Societal Test, and externalities.
- The testimony of Mr. Vumbaco on the need for eventual revisions to the IRP Ordinance.

II. NOPSI Credit for DSM Load Reductions

Q: Please describe your differences with Mr. Corder.

A: Mr. Corder concludes that jurisdictional avoided costs for NOPSI are lower than Entergy-wide avoided costs. As I explained in my direct testimony, NOPSI avoided costs are often *higher* than Entergy avoided costs, particularly in the short term.

Q: Please explain why NOPSI avoided costs are often higher than Entergy avoided costs, particularly in the short term.

A: The power-supply costs avoided by NOPSI are determined by the Entergy system agreement. Under that agreement, each member company must maintain capability equal to the system capability times its share of system load.[1] In effect, each company is required to maintain the system average reserve margin. Companies that have excess capacity (a higher-than-average reserve margin) reallocate the average costs of their "intermediate" units

[1]This load is measured as the average contribution to Entergy's twelve monthly peaks, rather than just annual peak load.

(defined as gas- and oil-fired steam plants, including combined cycles) to companies that are deficient (have lower-than-average reserve margins).[2] NOPSI and LP&L are now deficient and are expected to remain so. Thus, some of the capacity costs of intermediate plants owned by GSU and MP&L would be reallocated to NOPSI and LP&L.[3]

Reductions in NOPSI load increase NOPSI's reserve margin with its existing capacity, reducing the amount of other companies' excess capacity assigned to NOPSI. Hence, even in the period prior to the first avoidable capacity addition, when Entergy's avoidable generation capacity costs are zero, NOPSI can reduce its generation capacity costs substantially.

Q: Is Mr. Corder's conclusion about NOPSI avoided costs inconsistent with yours?

A: I do not believe so. Mr. Corder's is based on §6.1.2 and Technical Appendix 7B of the IRP, in which Entergy's discusses the assumptions it applied in projecting company-specific revenue requirements for future repowerings.[4] Mr. Corder does not purport to reflect the effects of reallocations of existing capacity. Thus, Mr. Corder's analysis omits NOPSI's savings due to reduction of the cost allocated to it from existing capacity.

[2]In my direct, I identified Waterford 3 as the last addition to the Entergy system. While this is correct, it is irrelevant, so long as LP&L is deficient. Also, my direct testimony relied on an older version of the System Agreement, in which the reallocated costs were from the last unit added. The current version of the System Agreement provides for reallocation of intermediate-unit costs.

[3]AP&L may also be slightly surplus.

[4]In keeping with its policy of not providing jurisdictional avoided costs, Entergy chose to ignore the annual reallocation of costs of existing units, including units whose retirement might be delayed.

Q: Can you give an example of how this omission affects Mr. Corder's results?

A: Yes. In his Exhibit JAC-2, Mr. Corder estimates the amount of new capacity for which NOPSI would be responsible in 2001 under three cases:[5]

- No DSM by any Entergy company.
- DSM by all companies, totaling 500 MW by 2001.
- Only NOPSI pursues DSM, saving 31 MW by 2001.

Mr. Corder assumes that the capacity position of each Entergy company would be determined by comparing its capability to its loads plus an 18% reserve margin.[6] He then follows the assumptions in LCIRP §6.1.2, and allocates the costs of any new capacity to be added in 2001 between companies in proportion to their capacity deficiency. He concludes that a 31 MW reduction in NOPSI load results in NOPSI avoiding 59 MW of additions if all Entergy companies participating in DSM, but only 12 MW if NOPSI goes it alone.

My Exhibit ____ (PLC-3) expands Exhibit JAC-2 by following the System Agreement more faithfully and including the allocation of existing

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[5]Mr. Corder's projections of load and capacity include GSU, some of his assumptions (including the need for power and the units to be added in 2001) are from sources other than the IRP, so they differ from those in my subsequent analysis. Since these analyses are examples, the differences are not consequential.

[6]This assumption is a simplification of the System Agreement, which sets capability responsibility equal to

$$\frac{\textit{company load}}{\textit{system load}} \times \textit{system capability}$$

so the required reserve for each company is the *actual* system reserve margin, not a planning target like 18%.

capacity. The more complete version of Mr. Corder's exhibit is summarized below:

	Total MW Deficiency	New Units	Reallocated Units	MW Savings
No DSM	160	59	101	—
All DSM	134		134	26
NOPSI-only DSM	126	47	79	34

In any of Mr. Corder's three cases, NOPSI would need more than 125 MW of additional capability (beyond what it owns today), most of which would be supplied by reallocations of existing units. NOPSI's capacity requirements are actually reduced more if the other companies do not pursue DSM.[7] In Mr. Corder's example, the 31 MW of NOPSI-only DSM would save NOPSI the costs of 12 MW of new (or repowered) capacity in 2001, as well as 22 MW of costs reallocated under Schedule MSS-1.

Q: Is it clear that NOPSI would be allocated the costs of only 59 MW of new capacity in the no-DSM case, given a deficiency of 160 MW?

A: No. It is important to recall that Mr. Corder is simply illustrating the effects of the cost allocation method Entergy used in the IRP. Nothing in the System Agreement specifies the cost responsibility for new units, other than the statements that

> 3.09 It is intended that each Company shall be willing and able to provide its portion of the major facilities determined to be necessary…

[7]If everyone conserves, system reserve margin is higher, and so is NOPSI's capability responsibility. Mr. Corder appears to assume that about 350 MW of retirements would be deferred in 1999–2001, regardless of the amount of DSM undertaken. This assumption is inconsistent with the LCP, and overstates reserves and NOPSI capability requirements, in the All-DSM Case. If half the scheduled retirements go forward in that time period, the system reserve would be reduced to 18% and NOPSI's capacity requirements would fall to 123 MW, increasing its savings to 37 MW for the All-DSM Case.

> 4.01 ...Each Company shall normally own, or have available to it under contract, such generating capability and other facilities as are necessary to supply all of the requirements of its own customers.

These provisions might be read as requiring NOPSI to pay the full cost of life extensions and repowerings, and purchase the full capacity of the life-extended or repowered units, until NOPSI "owns, or has available to it under contract" all the capacity necessary to meet its load and some reserve requirement. While the formula used in the IRP allocates to MP&L the costs of life-extending Rex Brown 1 (sometime between 1999 and 2002), the System Agreement might be interpreted to require NOPSI and LP&L to buy this unit's capacity at its full embedded cost, including life extension and sunk costs. In that case, Mr. Corder's example would change considerably, with NOPSI paying new-unit (or repowered or life extended) unit costs for substantially all of its deficiency, and saving 59 MW of those costs through the NOPSI-only DSM.

Q: What capacity responsibility can NOPSI avoid prior to the date at which Entergy can first avoid capacity costs?

A: Exhibit ____ (PLC-4) computes NOPSI capability responsibility for two cases:

- High growth: the IRP's supply-only load growth and capacity additions for all companies.[8]
- Low growth: identical to high growth, but with NOPSI load growth cut in half by DSM, as in the 1992 Least-Cost Plan.

As shown in Table 3 of Exhibit ____ (PLC-4), each MW reduction in NOPSI load growth reduces NOPSI capability responsibility by more than a

[8]Since the IRP does not include GSU, neither does this exhibit.

MW.[9] Through 1998 in the IRP high-growth case (and apparently through 2000 for the merged Entergy without DSM), all of NOPSI's generation capability savings would occur through the reserve equalization mechanism of Schedule MSS-1. From 1999 on, some of NOPSI's capacity savings would be priced at avoided purchases from other Entergy companies, or at the costs of life extension at NOPSI units, while a portion may still be priced under Schedule MSS-1.

Q: Are there any other costs covered by the Entergy System Agreement that are not reflected in Entergy's analysis?[10]

A: Yes. Service Schedule MSS-2 of the System Agreement provides for equalization between companies of "inter-transmission" capacity costs per kW of load, where inter-transmission facilities include the undepreciated portions of all lines over 230 kV, interconnections over 115 kV between utilities (either within Entergy or outside), and a portion of the costs of substations over 230 kV.

Q: Do you have an estimate of the value of Schedule MSS-1 and MSS-2 savings to NOPSI?

A: Yes. In February 1992, Entergy estimated the 1992 value of Schedule MSS-1 capacity to be $1.80/kW-month of capacity (or about $26/kW-year of peak load). The Entergy estimate is contained in Exhibit ____ (PLC-5). The same document gave a combined 1992 value of Schedule MSS-1 and MSS-2 of

[9]If NOPSI conserved, it would reduce the need for Entergy capacity additions. I have not taken this effect into account, so the Entergy system reserve margin is higher in Table 2 of Exhibit ____ (PLC-4) than in Table 1. This somewhat understates NOPSI's capability savings from DSM.

[10]Entergy's analysis is included in the direct testimony of James Kenney.

$2.52/kW-month, implying an MSS-2 value of $0.72/kW-month, or about $9/kW-year. Thus, the total value would be $35/kW-year in 1992. Adding in GSU's generally younger and more-expensive intermediate capacity is likely to have increased the Schedule MSS-1 rate. Over time, the value of Schedule MSS-1 is likely to rise, due to environmental compliance costs, life extensions, and additions of new intermediate capacity.[11]

Q: Are there other avoided capacity costs, beyond those covered by the System Agreement and by new generation additions allocated to NOPSI?

A: Yes. As discussed in my direct testimony, NOPSI does not appear to include any load-related transmission or distribution costs in its estimates of DSM savings.

III. The Screening Tests

Q: What screening test issues will you discuss?

A: I will respond to the following points raised by Mr. Silkman and Mr. Vumbaco on screening tests:

- the role of the RIM test,
- changes in the screening test definitions,
- the future of recommending that the Council abandon the societal test and any attempt to reflect externalities.

Q: How do you differ with the Advisors' testimony with regard to the role of the RIM test?

[11]Virtually all of the capacity additions projected in the 1992 IRP are life extensions and repowerings at existing intermediate plants.

A: Mr. Silkman correctly finds that the primary screening test for DSM options should be the TRC Test, rather than the RIM test, and the Ordinance provides for adequate review of the rate effects of DSM and the IRP.[12] Unfortunately, his testimony undermines his basic support of the "cost minimization goal of the Ordinance" (Silkman at 10, line 4–5) by suggesting that "the RIM Test has the potential to be used much more fully by the Companies" (lines 8–9).

As I explained in my direct testimony, the standard RIM test is not a useful measure of rate or bill effects. Demand-side-management programs can fail the RIM test without causing undue rate increases, while other programs that pass the RIM test may cause substantial short-term increases in rates (and even total energy bills). The emphasis should be on annual, class-specific analyses of rate and bill effects, not on RIM results.

The next several lines of Mr. Silkman's testimony (at 10, lines 9–15) might also be read as suggesting that, while "In some circumstances, it may be appropriate to implement demand-side programs that pass the TRC Test but fail the RIM Test," those circumstances might be quite limited. In general, Entergy should pursue the maximization of TRC benefits, even if *most* TRC-passing efficiency programs fail the RIM test. *If* the level of DSM that minimizes costs results in rate or bill effects that the Council finds unacceptable, Entergy should consider mechanisms for reducing those effects, including changing cost recovery patterns, changing program designs to reduce utility expenditures without sacrificing long-term savings, and stretching out retrofit programs over more years. In no case should any

[12]We agree that the primary test should be the TRC (or its variant, the Societal Test).

energy-efficiency measure or program be rejected simply because it fails the RIM Test.

As noted by all three Advisor witnesses, the current Ordinance provides ample opportunity for Entergy to submit alternative plans and argue for their adoption. Mr. Corder (at 8) discusses the value of alternative plans in giving the Council the flexibility to "determine the equity of 'trade-offs' between minimizing revenue requirements and minimizing rates, if applicable." I agree that Entergy should continue to be free to submit alternative plans that achieve goals other than minimizing costs, so long as a cost-minimizing plan is filed as well. I suggest that the Council

- reiterate its intention to minimize the total costs of energy services in New Orleans, to the extent feasible;
- remind Entergy that it will be expected to implement the least-cost plan unless compelling reasons can be shown for sacrificing these benefits;
- clearly state that small rate effects and a vague threat of competition do not constitute "compelling reasons."

Q: How do you differ with the Advisors' testimony with regard to changes in the screening test definitions?

A: Mr. Vumbaco suggests (at 10, lines 17–18) that "The Screening Test definition should be changed to incorporate Mr. Silkman's recommendations." I do not understand this recommendation, since I see nothing in Mr. Silkman's testimony (or elsewhere in the Advisors' testimony) that recommends or supports changes to the Screening Test definition.

Q: How do you differ with the Advisors' recommendation that the Council abandon the societal test and any attempt to reflect externalities?

A: Mr. Vumbaco (at 10, lines 18-19) suggests that "The Societal Test [should be] eliminated, as well as the requirement to monetize externalities."

I do not know the basis for Mr. Vumbaco's recommendations that the Council eliminate the Societal Test and thc monetization of externalities. Externalities are real costs and benefits, many of which will be borne by residents of New Orleans.[13] Environmental externalities, in particular, have been monetized by a number of regulators. Monetizing externalities is not burdensome or irrelevant, and incorporating externalties in Societal-Test screening is generally straightforward. The Council should retain the requirement for monetizing externalities, and for applying the Societal Test.

Q: Please explain the role that the Societal Test plays in the dual-screening-test process.

A: The inclusion of the Societal Cost Test (SCT) is integral to achieving the purpose of least cost planning as defined by the Ordinance of "satisfy[ing] future energy service demands at the least cost *to society,* balancing the interests of utility customers, utility shareholders and society-at-large." (City of New Orleans Ordinance No 14629 M.C.S. §52-351, "Definitions;" emphasis added.) Flexibility is given to this purpose through the use of a dual screening test and the filing of alternative plans.

Under the dual screening test, resource measures and programs must past either the TRC or the SCT. This ensures that externalities must be

[13]Environmental externalities affect the health and well-being of residents in the short run, and in the longer run may affect the costs of doing business, including generating electricity. Employment effects of various resources directly affect the well-being of those employed by the resources, as well as the businesses they patronize and the local governments that depend on local tax revenues.

considered at the screening level, providing a basis for later differentiating among various options when designing a preferred or alternative pan to minimize societal costs. It does not, however, determine that externalities must be included in the plan which is ultimately adopted.

Mr. Vumbaco (at 16) correctly argues:

> Alternative resource plans are a major component of the LCP process in that alternatives must be provided in order to provide adequate assurance that the ratepayers of New Orleans receive the benefits of a robust planning process.

The Ordinance ("Development of Least-Cost Resource Plans" at §52-356B), in addition to requiring the utility to develop resource plans to meet each demand forecast, requires it to develop resource plans

> to achieve different policy objectives as identified by the Collaborative Working Group (for example minimizing customer bills, minimizing rates, minimizing customer direct costs, maximizing environmental protection, maximizing penetration of Demand-Side Resources), based on the Least-Cost combination of the potential Demand-Side and Supply-Side Resources assessed.

The development of alternative plans then provides a basis for the utility to justify the selection of its "preferred plan" (§52-356E).

The City Council then has the responsibility for determining

> which combinations of resource options passing the Screening Test best serve the public interest considering economics, safety, reliability, flexibility, risk, equity among ratepayers and classes, customer bills, Externalities and other factors as may be determined appropriate by the City Council. (§52-357F)

The form in which information is prepared allows for the flexibility to balance and choose among varying objectives. It is appropriate that this choice be made only after it is possible to compare the results. The results may show that achieving one possible objective, for example maximizing environmental protection, will only have minimal effect on another objective which the regulator holds of importance, for example minimizing bills. Based on such information, the regulator may find that it is the public interest to select the plan which best achieves both objectives. Not including the SCT as part of the screening process would deprive the City Council of the information necessary to make such a judgment fairly.

IV. Revisions to the IRP Filing Requirements

Q: What is the position of the Advisors with respect to changing filing requirements in the Ordinance?

A: Mr. Vumbaco correctly concludes that Entergy's proposal to dismantle the Ordinance and replace it with "informational" filings is not in the best interest of New Orleans. He observes that the Ordinance is flexible enough to accommodate consideration of Entergy's concerns with respect to rate effects and load building, and that many of the requirements Entergy claims to find burdensome are necessary in resource planning.

He then suggests (at 13) that the Council consider revisions in the detailed requirements of the Ordinance. Mr. Vumbaco maintains that the core elements of the Ordinance are sound and appropriate for planning, but suggests that some of the more prescriptive provisions should be eliminated. He argues that because results are most important, NOPSI should be allowed more latitude in its planning analysis, without having to provide the details of load flow studies, load forecasts, and other requirements in the filed plan. Mr. Vumbaco (at 14–16) list sections of Ordinance that he believes could be "streamlined."

It is not clear when and how Mr. Vumbaco proposes that the Council consider these streamlining changes, although he appears to be proposing a separate proceeding for this purpose. I recommend a further streamlining of Mr. Vumbaco's recommendation.

Q: How might Mr. Vumbaco's recommendation be further streamlined?

A: No formal proceeding or change to the Ordinance is necessary.

The Ordinance already provides considerable flexibility, allowing Entergy to seek exemptions from the Council for specific filing requirements. In addition, as noted in the Council Resolution R-93-12 (February 4, 1993), Entergy has not always felt compelled to file all the analyses required by the Ordinance. Rather than drag out this process with yet more hearings, the Council can simply encourage Entergy to file notice with the Council and parties identifying the following exemptions for the 1995 IRP:

- Data categories that have not changed substantially and have not been updated for Entergy's internal purposes, for which Entergy proposes to reference the data in the 1992 IRP (such as the first seven years of the ten years of historical data for existing resources).
- Data that are burdensome to assemble and reproduce in the IRP or its appendices, but which Entergy proposes to make available to the Council and parties in another format.
- Information that Entergy proposes to provide in a different order or format than required in the Ordinance, specifying the proposed changes (such as combining text and appendices, or covering two related topics in a single section of the IRP).

- Analyses for which Entergy proposes to substitute slightly different analyses that provide similar information, such as the transmission studies described by Mr. Vumbaco (at 13).
- Data and analyses that is not necessary for development of the least-cost plan. I agree with Mr. Vumbaco that estimating full DSM technical potential is not necessary; Entergy's time and effort would be better applied to identifying DSM market segments, and designing programs to achieve the full feasible cost-effective potential in each segment. Mr. Vumbaco may also be correct in asserting that *fully* developing resource plans for each forecast scenario is excessive; at a minimum, Entergy should determine resource plans for extreme situations (e.g., high and low growth, high and low capacity need, high and low fuel costs) in enough detail to allow Entergy and the Council to determine the range of potentially cost-effective DSM savings, repowerings, life extensions, new capacity and other major resource decisions.

Q: Do you agree that the Council should reconsider the Collaborative Working Groups, as Mr. Vumbaco suggests (at 15 and 16)?

A: No. Mr. Vumbaco does not explain why he believes the Council should reconsider the role of the CWGs, or (at 16 line 4) how their roles might be "clearly redefined." As I discussed in my direct testimony, collaboratives can be very helpful in increasing the effectiveness of utility planning, particularly with respect to DSM program design. The collaborative, if fully utilized by Entergy, could also facilitate regulatory review and Entergy's operational flexibility. The Council should strengthen the CWGs, not limit them.

Q: Do you agree that the IRP cycle can be extended to three years, from the current two years, as Mr. Kenney recommends (at 32) and Mr. Vumbaco supports (at 18)?

A: Yes. This is the de facto schedule for 1992–95. However, in other jurisdictions that have a three-year IRP cycle, some form of annual filing, such as a Short-Term Action Plan (STAP), is usually required to update DSM plans, retirements, repowerings, purchases, sales, and the like. If Entergy is allowed to delay its next IRP until 1998, it should be required to prepare annual STAPs for 1996 and 1997.

Q: Does this conclude your rebuttal testimony?

A: Yes.

Exhibit____(PLC- 3)
Expansion of Exhibit JAC-2

	No DSM on System		DSM on All Companies		NOPSI DSM Only	
	NOPSI	System	NOPSI	System	NOPSI	System
1 capacity after additions	1288	21994	1229	21574	1276	21994
2 load	1176	18623	1145	18123	1145	18592
3 reserve margin		18.1%		19.0%		18.3%
4 capability responsibility	1389		1363		1355	
5 MW allocated by agreement	101		134		79	
6 MW allocated by Corder	59		0		47	
7 total capacity added	160		134		126	
8 Savings from no-DSM case			26		34	
9 NOPSI MW load reduction			31		31	
10 Ratio of avoided capacity to load reduction			83%		111%	

Exhibit____(PLC- 4)
Capacity Equalization: NOPSI Low Growth.

	Loads[1]					Capacity [2]					Additions[3]				
	NOPSI	APL	MPL	LPL	System	NOPSI	APL	MPL	LPL	System	NOPSI	APL	MPL	LPL	System
1995	1163	4064	2469	5022	12718	1245	5243	3458	5698	15644					
1996	1168	4158	2523	5082	12931	1245	5243	3458	5698	15644					
1997	1173	4254	2578	5143	13149	1248	5249	3463	5700	15660	3	6	5	2	16
1998	1178	4352	2635	5205	13370	1251	5255	3468	5702	15676	3	6	5	2	16
1999	1183	4453	2692	5267	13596	1251	5285	3504	5725	15765		30	36	23	89
2000	1188	4556	2751	5331	13826	1313	5491	3508	5881	16193	62	206	4	156	428
2001	1193	4661	2812	5395	14060	1403	5722	3513	6019	16657	90	231	5	138	464
2002	1198	4768	2873	5459	14300	1432	5937	3582	6203	17154	29	215	69	184	497

Sources:

[1] Low Growth: Least Cost Integrated Reousce Plan Peak Loads, Table 8.9, page 8-14.
[2] Operating Company Distribution of Capability, Table 4.1, page 4-2.
[3] Supply-Side-Only Plan Supply-Side Addition Schedule, Table 6.3, page 6-8.

	NOPSI	APL	MPL	LPL
growth	0.43%	2.31%	2.19%	1.20%

Exhibit____(PLC- 4)
Capacity Equalization: NOPSI Low Growth

reserve margin

Equalization MW Position Status

	Loads[1]	Capability Responsibility				Capacity [2]			
		NOPSI	APL	MPL	LPL	NOPSI	APL	MPL	LPL
1995	23.0%	1,431	4,999	3,037	6,177	(186)	244	421	(479)
1996	21.0%	1,413	5,030	3,052	6,148	(168)	213	406	(450)
1997	19.1%	1,397	5,066	3,071	6,126	(149)	183	392	(426)
1998	17.2%	1,381	5,103	3,089	6,103	(130)	152	379	(401)
1999	16.0%	1,372	5,163	3,122	6,108	(121)	122	382	(383)
2000	17.1%	1,392	5,336	3,223	6,243	(79)	155	285	(362)
2001	18.5%	1,414	5,522	3,331	6,391	(11)	200	182	(372)
2002	20.0%	1,438	5,720	3,447	6,549	(6)	217	135	(346)

Sources:

[1] Low Growth: Least Cost Integrated Reousce Plan Peak Loads, Table 8.9, page 8-14.
[2] Operating Company Distribution of Capability, Table 4.1, page 4-2.
[3] Supply-Side-Only Plan Supply-Side Addition Schedule, Table 6.3, page 6-8.

Exhibit____(PLC- 4)
Capacity Equalization: NOPSI High Growth

	Loads[1]					Capacity [2]					Additions[3]				
	NOPSI	APL	MPL	LPL	System	NOPSI	APL	MPL	LPL	System	NOPSI	APL	MPL	LPL	System
1995	1163	4064	2469	5022	12718	1245	5243	3458	5698	15644					
1996	1172	4158	2523	5082	12936	1245	5243	3458	5698	15644					
1997	1182	4254	2578	5143	13157	1248	5249	3463	5700	15660	3	6	5	2	16
1998	1191	4352	2635	5205	13383	1251	5255	3468	5702	15676	3	6	5	2	16
1999	1201	4453	2692	5267	13614	1251	5285	3504	5725	15765		30	36	23	89
2000	1211	4556	2751	5331	13849	1313	5491	3508	5881	16193	62	206	4	156	428
2001	1221	4661	2812	5395	14088	1403	5722	3513	6019	16657	90	231	5	138	464
2002	1231	4768	2873	5459	14332	1432	5937	3582	6203	17154	29	215	69	184	497

Sources:

[1] High Growth: 1992 Business Plan Peak Load.
[2] Operating Company Distribution of Capability, Table 4.1, page 4-2.
[3] Supply-Side-Only Plan Supply-Side Addition Schedule, Table 6.3, page 6-8.

growth	0.81%	2.31%	2.19%	1.20%

Exhibit____(PLC- 4)
Capacity Equalization: High Growth

	Loads[1]	Capability Responsibility				Capacity [2]			
		NOPSI	APL	MPL	LPL	NOPSI	APL	MPL	LPL
1995	23.0%	1,431	4,999	3,037	6,177	(186)	244	421	(479)
1996	20.9%	1,418	5,028	3,051	6,146	(173)	215	407	(448)
1997	19.0%	1,407	5,063	3,069	6,122	(159)	186	394	(422)
1998	17.1%	1,396	5,098	3,086	6,097	(145)	157	382	(395)
1999	15.8%	1,391	5,156	3,118	6,100	(140)	129	386	(375)
2000	16.9%	1,416	5,327	3,217	6,233	(103)	164	291	(352)
2001	18.2%	1,443	5,511	3,324	6,378	(40)	211	189	(359)
2002	19.7%	1,473	5,708	3,439	6,534	(41)	229	143	(331)

Sources:

[1] High Growth: 1992 Business Plan Peak Load.
[2] Operating Company Distribution of Capability, Table 4.1, page 4-2.
[3] Supply-Side-Only Plan Supply-Side Addition Schedule, Table 6.3, page 6-8.

Exhibit____(PLC- 4)
Capacity Equalization: NOPSI Summary of Results

Summary of results

	High NOPSI Growth			Low NOPSI Growth			Differences	
	NOPSI Load	NOPSI Cumulative Additions	NOPSI MSS-1 Reallocation	NOPSI Load	NOPSI Cumulative Additions	NOPSI MSS-1 Reallocation	NOPSI Load	Total NOPSI Capacity
1995	1163	0	186	1163	0	186	0	0
1996	1172	0	173	1168	0	168	4	5
1997	1182	3	159	1173	3	149	9	10
1998	1191	6	145	1178	6	130	13	15
1999	1201	6	140	1183	6	121	18	19
2000	1211	68	103	1188	68	79	23	24
2001	1221	158	40	1193	158	11	27	29
2002	1231	187	41	1198	187	6	32	35

Note:
Totals may differ because of rounding errors.