Public Power Council
1500 NE Irving, Suite 200
Portland, Oregon 97232
(503) 232-2427
FAX (503) 239-5959

NOV 2 9 2004

November 24, 2004
Submitted Electronically and Via U.S. Mail

Mark Walker
Director of Public Affairs
Northwest Power & Conservation Council
851 SW 6th Avenue, Suite 1100
Portland, Oregon 97204-1348
comments@nwcouncil.org

Re: The Draft Fifth Pacific Northwest Electric Power and Conservation Plan

Dear Mark,

Thank you for this opportunity to comment on the Northwest Power & Conservation Council's (the Council) draft Fifth Power Plan (the Plan). The Plan is quite expansive, so for efficiency's sake we will limit our comments to several top priority topics.

Allocation of the Federal Columbia River Power System (FCRPS)

We concur with the Plan's recommendation that the existing FCRPS[1] should be allocated out to Bonneville Power Administration's (BPA) eligible customers at cost, but we clarify that this class of customers should be limited to consumer-owned utilities currently purchasing firm power from BPA. The Public Power Council's (PPC) Executive Committee has presented BPA its unanimously adopted proposal for allocating the system to public power that we believe meets three important principles:

[1] The Plan calls for an allocation of the FCRPS. This implies that BPA's transmission assets are included in the allocation, in addition to its generation output. PPC and others have focused solely on an allocation of the Federal Base System (FBS), or "the output of the existing federal hydroelectric resources at Army Corps of Engineers and Bureau of Reclamation dams, plus other resources Congress has authorized BPA to acquire, including the output of the Columbia Generating Station". (Public Power Chronicle, p. 100).

Fifth Power Plan/November 2004/Comments/149

1) Treat all publics in a fair and equitable manner;

2) Be broadly acceptable to public power utilities; and

3) Be transparent and understandable.

We see a fundamental flaw in the Plan's recommendation for allocation, with utilities taking on more responsibility for resource development and acquisition thereby relieving BPA of the responsibility, when the Council also recommends that BPA aggressively acquire substantial additional conservation, renewable, and other resources. One purpose of allocation is to limit BPA's role as a resource acquirer, but the Plan focuses almost entirely on BPA's potential resource acquisitions. This is most notable in the Plan's Implementation section, which focuses solely on BPA's responsibility to comply with the Plan's directives. More time should be spent on how the region can address the Plan's recommendations.

Regional Conservation Target

The Plan is a 20-year look at regional resource development, with a 5-year Action Plan, both updated five years from the adoption of this Plan. The Council chose from three options in developing its 5-year conservation targets, two of which result in identical 20-year conservation savings that are considerably higher than the third alternative. The Plan recommends Option 3, the more aggressive path in getting to the higher conservation level. We believe that Option 3's 5-year regional conservation target of 700 aMW is too aggressive and will be too hard to attain at low-cost to utilities.

This 5-year target translates to an average yearly target of 140 aMW of total conservation. By the Council's own admission, the region has accomplished over 140 aMW of annual conservation only once, at the height of the west coast energy crisis, in 2001. In 1995 the region conserved 130 aMW and in 1993 it conserved 120 aMW of electricity. The region has been unable to accomplish more than 120 aMW of conservation in any other years.

The Council could have based its 5-year plan on Option 2 (500 aMW of regional conservation in five years), which results in annual conservation targets that more closely resemble what the region has been able to accomplish. This option still has the feature of getting the region to 2800 aMW of conservation by 2025. We believe Option 2 is more manageable and attainable for the region. The region's ratepayers are still working to recover from the power rate increases of the past several years and we fear that the higher conservation target could add undue rate pressure to BPA's already very expensive rates. Alternatively, it could

force BPA to adopt a new conservation program that is too draconian for utilities to be able to participate in, thereby forcing BPA to serve as the backstop and removing the widely appreciated attributes of BPA's current conservation programs—local control and local investment. We also note that there has been substantial price-induced conservation in the region over the last few years, due to increases in electrical rates, which has added to the programmatic conservation sponsored by utilities.

BPA's Role

The Plan's eleventh section focuses on the future role of BPA in power supply. We find that several of the recommendations for BPA in this section problematic. In addition, there are recommendations on a regional level that would also be a problem if BPA is viewed as being the backstop, should the region prove unsuccessful at complying with these recommendations. Because our concerns in both cases are about BPA's role in the region, we address both sets of problems together, below.

We acknowledge the daunting number of details that still must be sorted out before BPA can offer acceptable 20-year contracts implementing an allocation of the FBS in FY12. We hope to hasten progress toward that end by meeting the Plan's goal of new contracts by October 2007, and even BPA's more ambitious goal of December 2006. We do not agree with the Plan's proposed sanctions of tiered rates, potential rulemaking, and new legislation, should the region not have new contracts by October 2007. We fear that rushing the policy development process and contract negotiations, just to stave off an ugly alternative, might make for poor policy development.

We will not reiterate the full content of our comments to BPA regarding its proposal to offer the Direct Service Industries (DSIs) 500 aMW of power or financial benefits, but we will summarize them here as they similarly apply to the Plan's recommendation that BPA augment the FBS to provide a limited amount of power to the DSI for a limited period of time. Since the passage of the Northwest Power Act, the DSIs have known that 2001 was the end of the time period for which BPA had a statutory obligation to provide power to the DSIs. During that period (between 1981 and 2001), the DSIs were to develop alternate resources, or otherwise find power sources, to serve their load. They did not succeed in doing so. PPC believes the DSIs should be allowed to seek service from their local utility on a basis similar to that of other (non-DSI) industrial customers.

The Plan recommends that BPA and its customers work toward a new settlement of the benefits to the investor-owned utilities' (IOUs) small farm and residential customers, in time to support BPA's offering of new long-term

contracts by October 2007. BPA and the IOUs have already negotiated a resolution to any FY07-11 IOU benefit uncertainty, from their perspective. PPC and others continue to litigate the validity of the underlying contracts in the Ninth Circuit Court of Appeals. As far as IOU benefits post-2011 are concerned, we believe they should be financial in nature, and should comply with the provisions of the Northwest Power Act.

As far as BPA's next rate period is concerned, we agree with the Council's recommendation that within the portfolio of mechanisms BPA employs to encourage conservation, it should employ a mechanism similar to the current Conservation and Renewables Discount (C&RD) program to help the region's utilities acquire conservation. There are ways to enhance this program, incorporating lessons learned during the current rate period, and we hope to work with BPA and the Council to do so. Our members are overwhelmingly in favor of retaining the existing program in the next rate period, with minor enhancements, because it is user-friendly, flexible, and locally controlled and it funds administrative costs. Moreover, it has been very successful at accomplishing conservation across the region. We agree that BPA, in light of BPA's intention to move away from resource acquisition (except to provide service that specific utilities request and for which they agree to pay all of the associated acquisition costs), should move towards being a facilitator of renewable resources development.

The Plan suggests that the region should be poised to bring on 400 aMW of coal-fueled power generation by 2013 (with construction beginning in 2010), should the region meet the conservation targets proposed in the Plan. The transmission needed to integrate this coal capability into the grid would be completed by 2009, and pre-construction development for the coal-fired projects to begin by 2006. To the extent the Plan assumes a BPA investment or acquisition role in this coal plant development, that role should be limited by bilateral contracts with those utilities specifically requesting that resource's output to serve their load growth and promising to pay the full costs of the acquisition.

The Plan also asks the region to work on ways to implement demand response mechanisms more fully, such as demand "buybacks". We support the Plan's Action DR1, which asks that BPA and utilities "work to reduce the transaction costs of these programs by streamlining recruitment of participants, notification of buyback opportunities, and verification of, **and compensation for**, demand reductions". (P. AP-7, emphasis added). We do not think that the best time for BPA to negotiate compensation for such a buyback deal is in the heat of a crisis. A brief review of the west coast power crisis amply explains this position. These opportunities should be clearly defined and assigned a compensation cap, established well in advance of any future buyback offers by BPA.

Council's Role

We question the appropriateness of the Plan's recommendation that the Council be "vigorous in its oversight of Bonneville's actions", implying "regular and systematic review by the Council and Council staff on what Bonneville is proposing and doing with regard to power supply and resource acquisitions and the associated issues of load service, contracts, rates, and other matters addressed in this power plan". (P. 12-3). Specifically, the Plan calls for "regular reporting (perhaps quarterly) from Bonneville on relevant issues such as load obligations, resources available; a rolling forecast of what Bonneville expects in terms of loads and resources; power sales and forecasts of power sales (including surplus sales); progress on acquisitions of conservation and renewable resources that reduce load; actions or plans for actions to augment the system or acquire resources (including spot market and short-term power purchase contracts); Bonneville costs of serving load; and more". (P. 12-4).

The region and BPA have tried to reduce current operating costs and those forecasted for the future. We fear that the new reporting requirements the Council intends impose will divert much needed BPA attention away from developing and implementing new BPA policies suggested in the Regional Dialogue. Further, increased reporting by BPA in some of those areas would necessitate increased reporting by BPA's customers, raising the costs of doing business with BPA for PPC's members.

We suggest that the Council monitor the region's progress towards ushering in the new 20-year contracts and an allocated world, but not be overly demanding of BPA in doing so. The Council's role has traditionally focused on the development of 1) 20-year regional electric power plans; and 2) plans to ensure fish and wildlife protection. These actions have never implied micromanaging BPA's relationship with its customers.

Transmission

The Draft Power Plan notes that problems exist in the Northwest transmission and power systems, and suggests that "[i]t should be a high priority for regional interests to work through the Grid West RRG process to address emerging transmission issues within the next two years" (P. AP-16). While there is consensus that problems exist, there is no clear consensus on the significance or relative priority of those problems. Nor is there consensus on the means for solving those problems.

Although PPC has taken no position on the desirability of Grid West, PPC has reached two conclusions about the development of Regional Transmission Organizations (RTOs)[2]:

1) FERC control of regional energy policy is undesirable; and

2) RTOs in the U.S. have proven to be extremely expensive.

With regard to the first point, PPC believes that FERC does not understand the Northwest power and transmission systems and wholesale markets required to make informed judgments about the needs of the Northwest. FERC has been bent upon a path of standardized integrated markets, financial rights and transmission services and has made extremely unwise decisions in the past when confronted with market crises. None of its actions in the past several years give us any comfort that FERC will make decisions that are in the best interests of the region.

FERC's policy of "encouraging" RTO development is troubling in light of the second point. Each operating U.S. RTO and ISO has demonstrated a similar pattern of growth of its annual operating costs.[3] In 2004, existing RTOs and ISOs will spend, collectively, over $1 billion in operating costs.[4] For the RTOs and ISOs that provide data on annual energy, this works out to a weighted average unit cost of $0.73/MWh (2003 dollars).[5] We have seen no conclusive evidence of offsetting benefits reflected in retail bills. Consumers in some areas have experienced rate decreases due solely to price caps. When price caps are removed, consumers in many areas (such as California, New Jersey, Ohio and Maryland) face large rate hikes. Overall, there is no credible analysis we have seen that demonstrates a net benefit from RTOs. PPC remains skeptical that the imposition of an RTO in the Northwest would produce net benefits for consumers in each affected state. Even with a scaled-down version of an RTO, it is unclear that the benefits will outweigh the costs.

Bear in mind, too, that the concept of a scaled-down RTO that performs limited functions necessarily assumes that FERC will permit a jurisdictional transmission operator to perform less than all RTO functions. To date it has not

---

[2] RTOs have also been referred to as Independent System Operators (ISOs).

[3] *See* Margot Lutzenhiser's study entitled Comparative Analysis of RTO/ISO Operating Costs, August 17, 2004 (Lutzenhiser), p. 4. This study has been appended to these comments.

[4] *See* Lutzenhiser, p. 3. Operating costs are in 2003 dollars and include amortization, depreciation and interest expenses. On an individual basis, these costs range from $119 to $229 million for 2004 (2003 dollars). *See* Lutzenhiser, pages 9 - 15.

[5] Calculated as a weighted average using operating cost data. *See* Lutzenhiser, pages 9 - 15. Note that MISO does not collect data regarding annual energy for its service territory but inclusion of that data in this calculation could reduce the average unit cost.

done so. In every case FERC has required the RTO or ISO to perform more functions than those it performed at start-up.

Along with current RTO efforts, groups are working on solutions to regional transmission needs, including the Northwest Power Pool and the Transmission Issues Group. PPC urges the Council to support these efforts as well, because these efforts are more likely to produce timely solutions to the most pressing problems.

Thank you again for the opportunity to comment.

Sincerely,

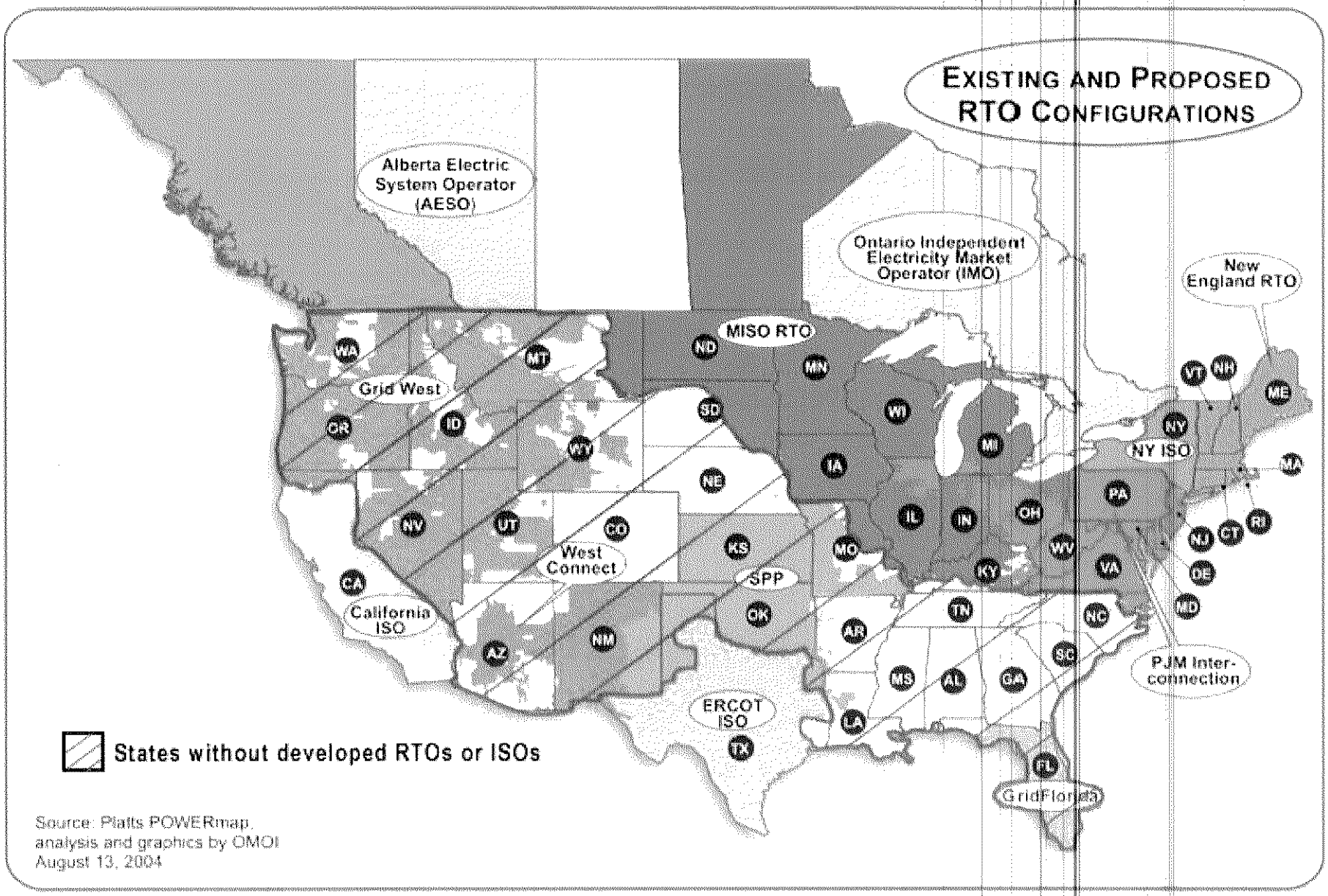
C. Clark Leone
Manager

Comparative Analysis of RTO/ISO Operating Costs

August 17, 2004

Margot Lutzenhiser
Associate Economist
Public Power Council

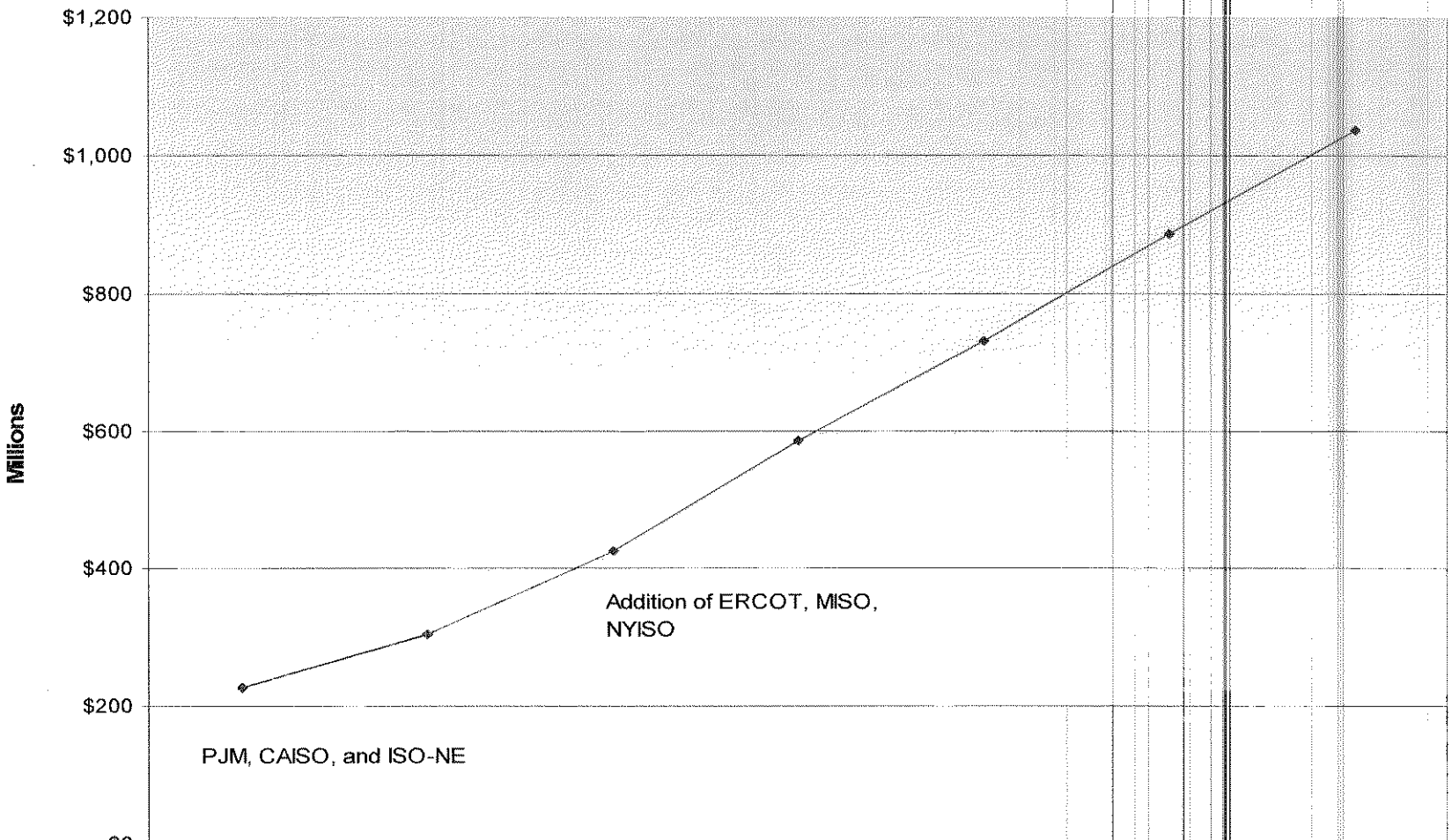
Margotl@ppcpdx.org



Source: http://www.ferc.gov/industries/electric/indus-act/rto/rto-map.asp

© 2004 All Rights Reserved

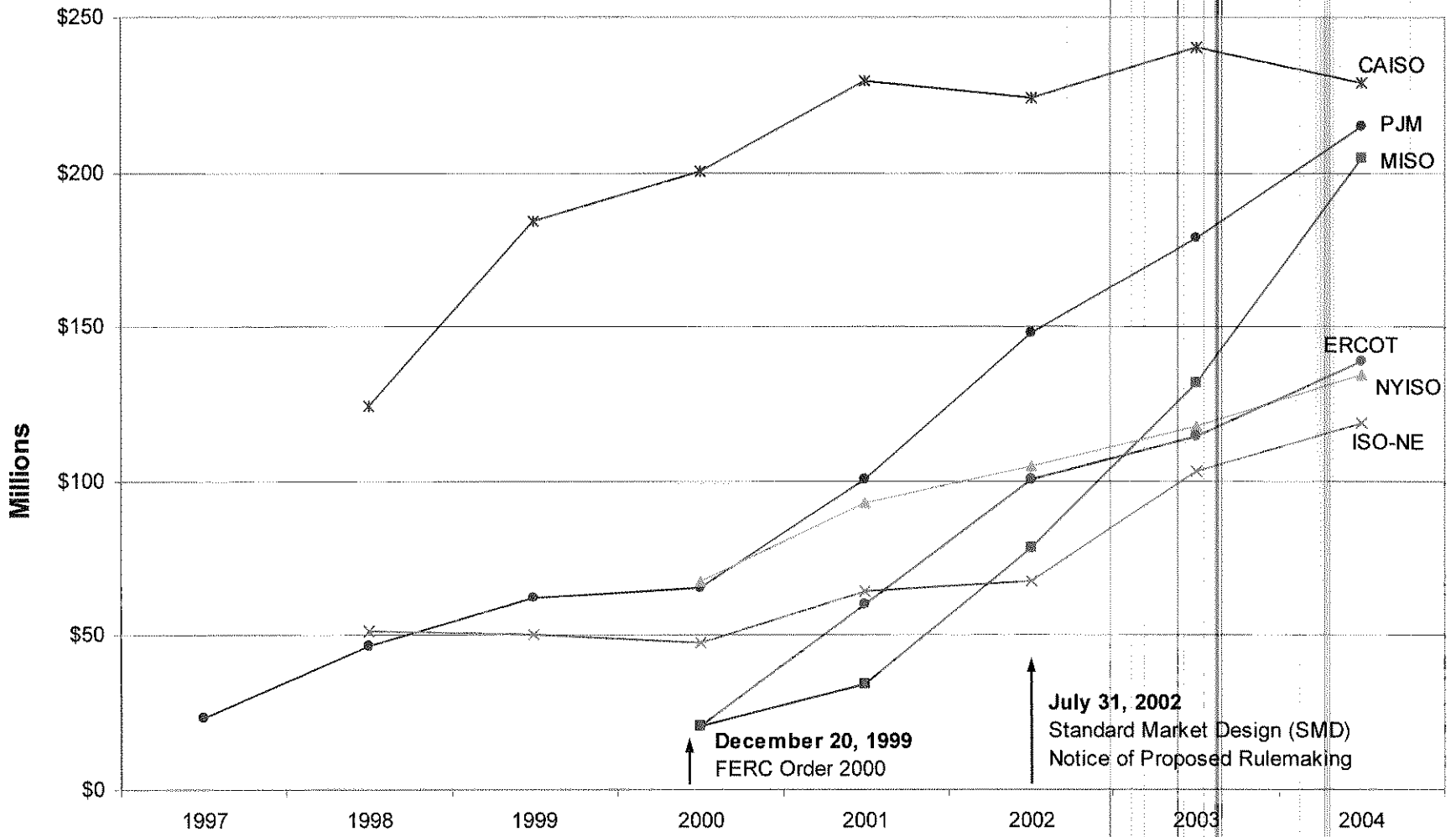
Annual U.S. RTO/ISO Operating Costs (2003 dollars)



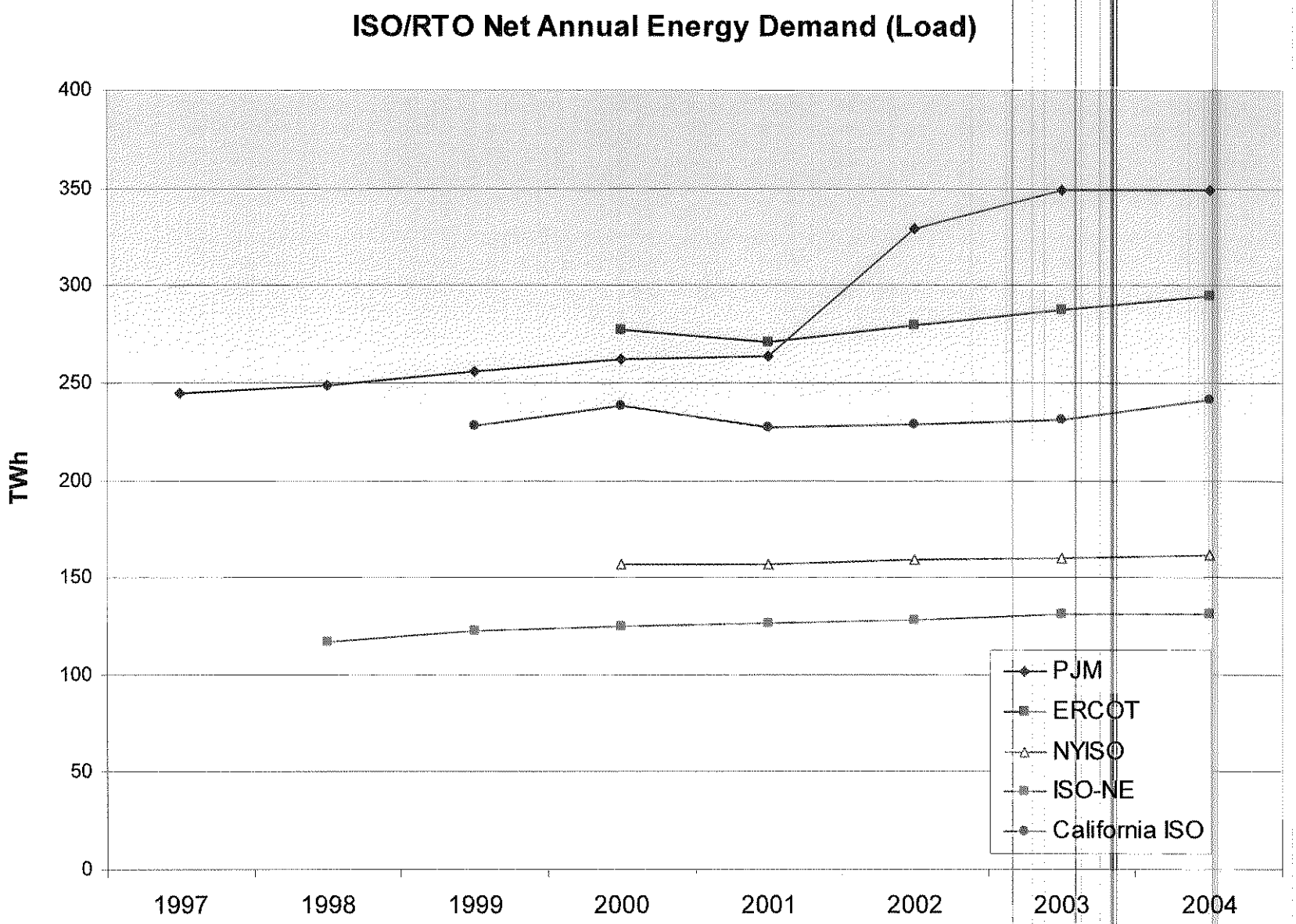
	1998	1999	2000	2001	2002	2003	2004
RTO Expenses	$226,771,863	$302,836,246	$424,926,009	$584,279,480	$730,160,074	$885,701,442	$1,035,338,562

© 2004 All Rights Reserved

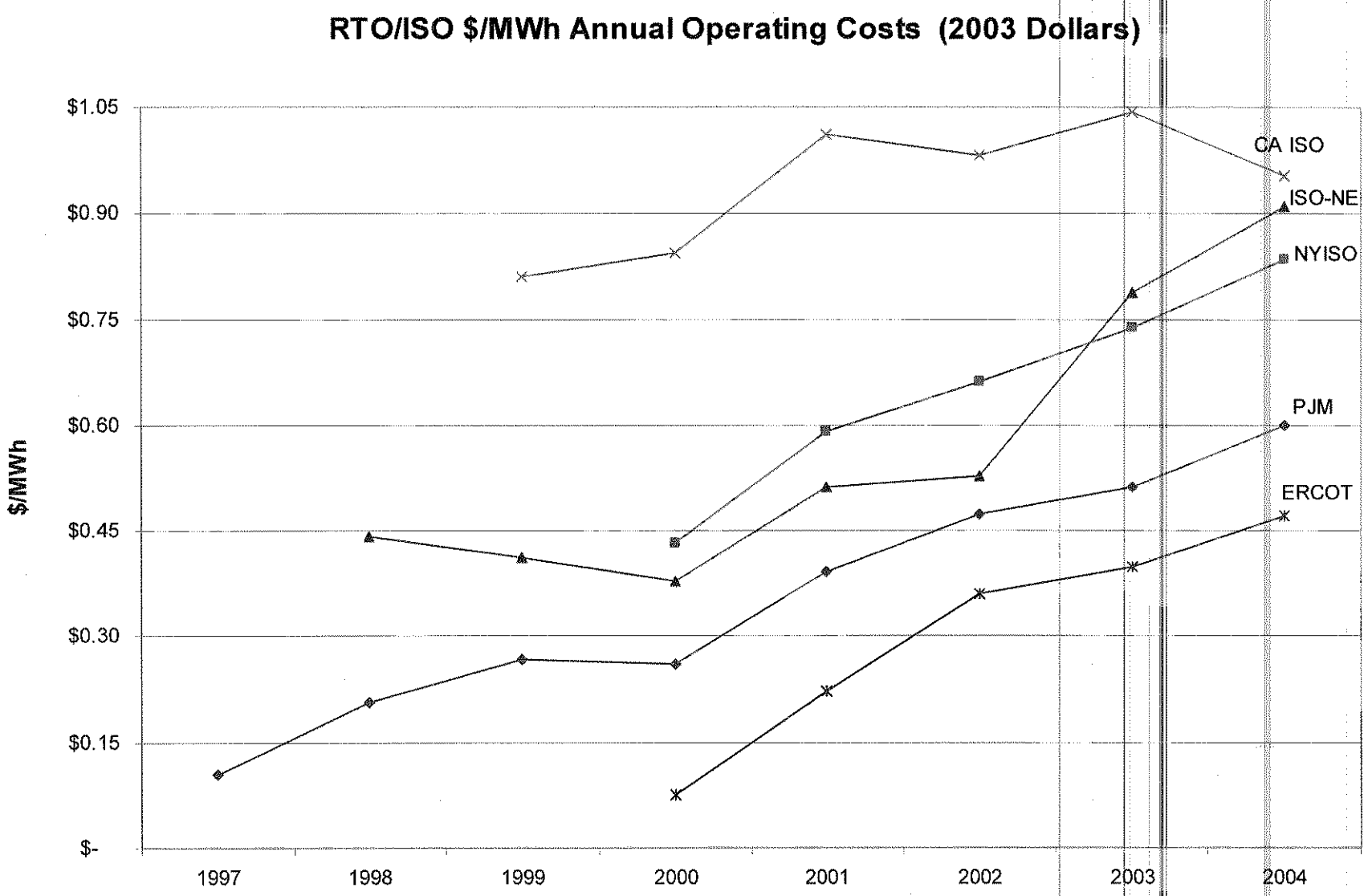
ISO/RTO Annual Operating Costs (Including Amortization, Depreciation and Interest Expenses in 2003 dollars)



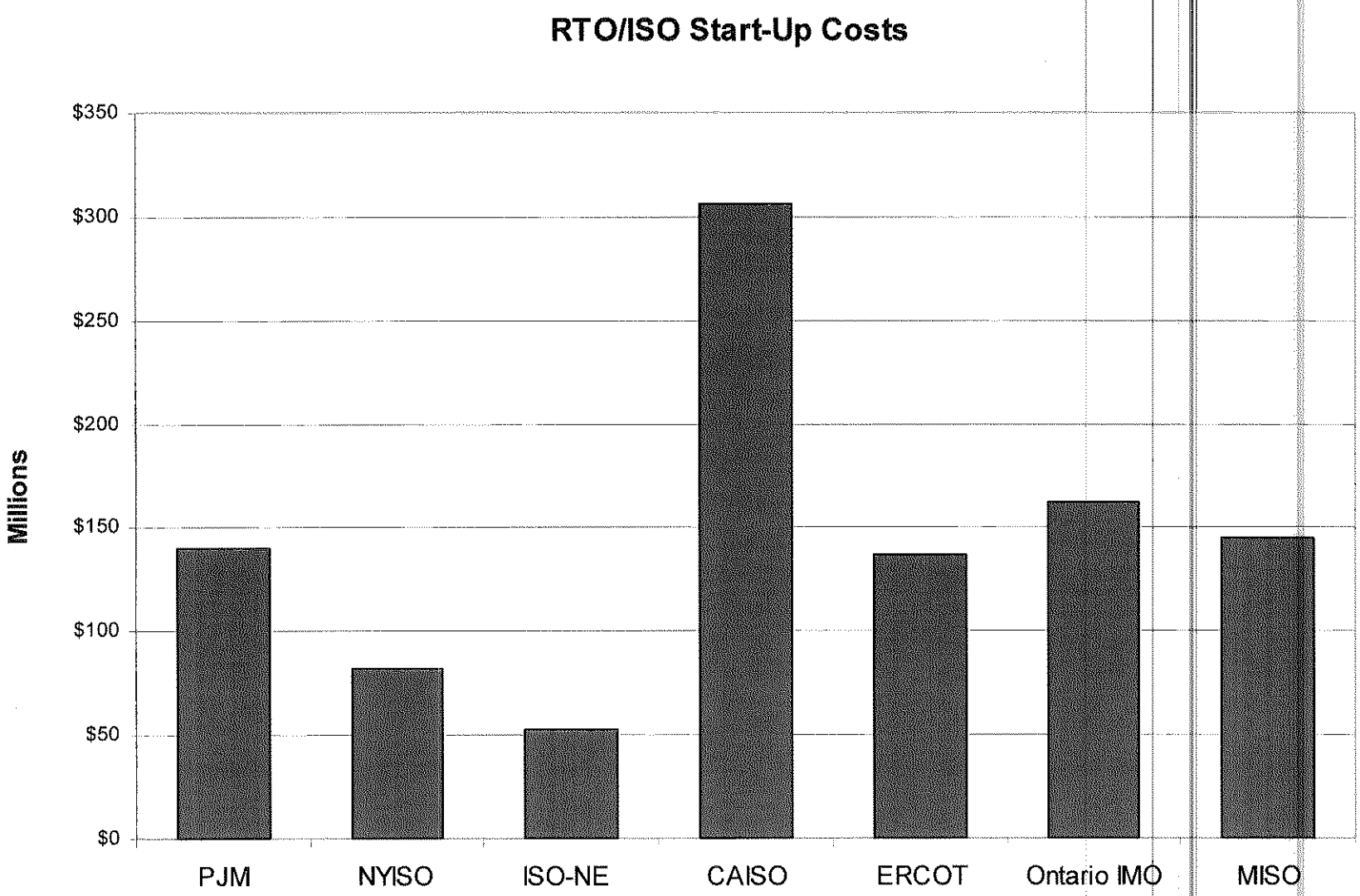
© 2004 All Rights Reserved



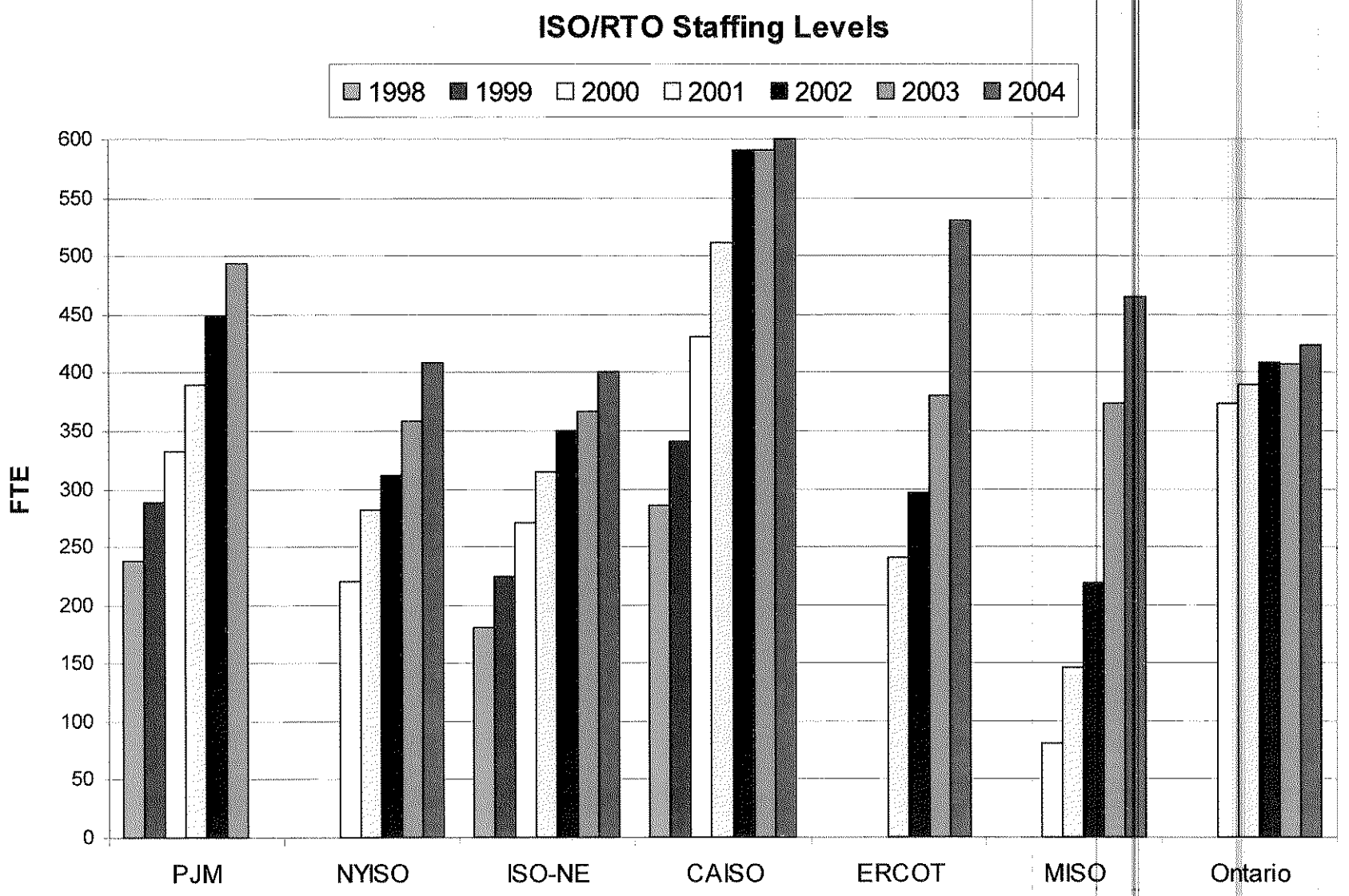
© 2004 All Rights Reserved



© 2004 All Rights Reserved



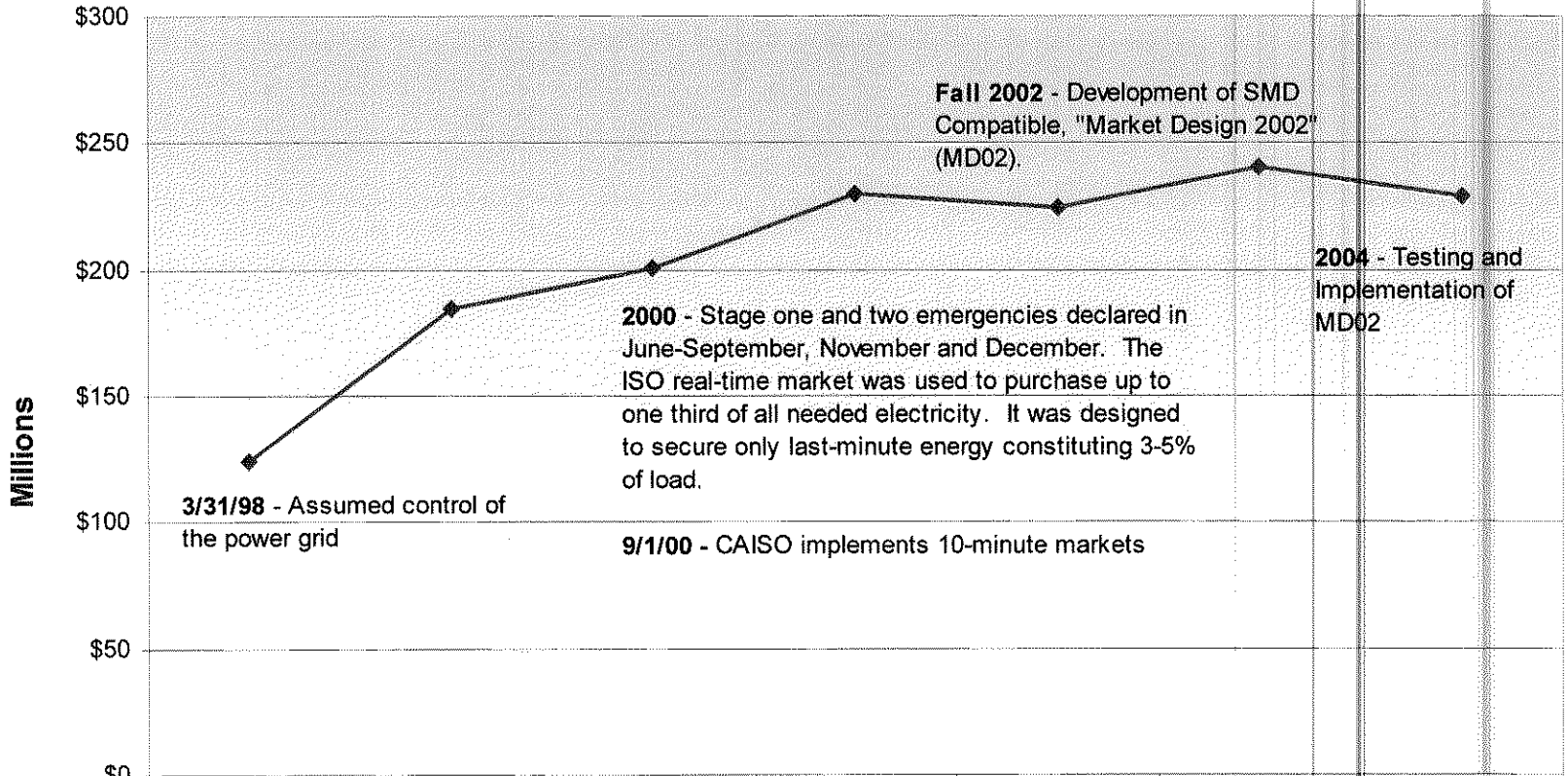
© 2004 All Rights Reserved



* It is unclear whether contractors are included in some data points. FERC Form 1 data do not include contractors. For consistency, contractors have been excluded whenever possible. (Sources provided on slides 16-18.)

© 2004 All Rights Reserved

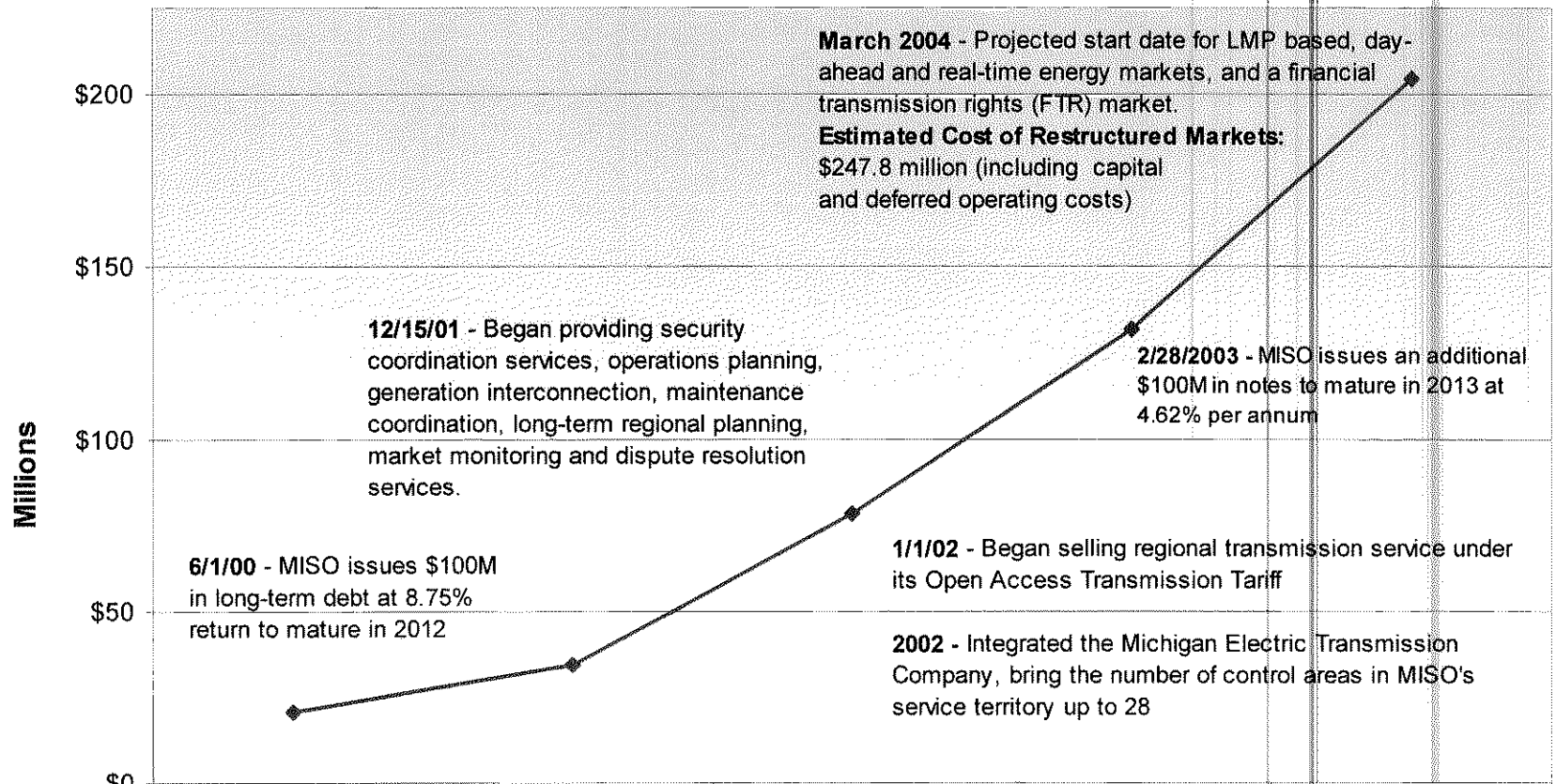
California ISO Annual Operational Costs (2003 dollars)



	1998	1999	2000	2001	2002	2003	2004
Op Costs	$123,969,114	$184,245,582	$200,490,117	$229,737,582	$224,090,535	$240,411,000	$229,182,674
% Change		48.62%	8.82%	14.59%	-2.46%	7.28%	-4.67%
Staffing	286	341	431	511	590	591	599
% Increase	-	19.23%	26.39%	18.56%	15.46%	0.17%	1.35%

© 2004 All Rights Reserved

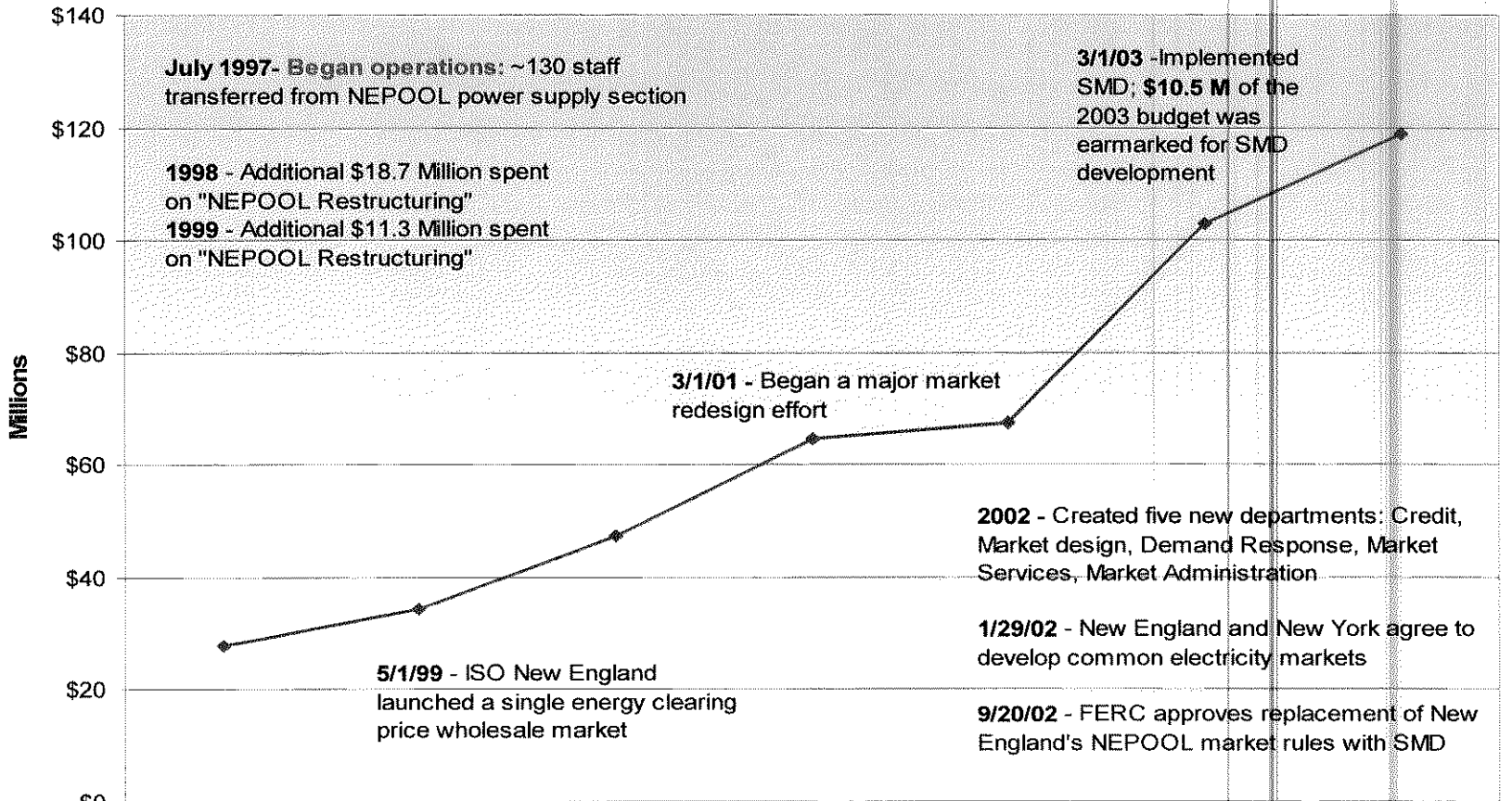
Midwest ISO Annual Operating Costs (2003 Dollars)



	2000	2001	2002	2003	2004
Op Cost	$20,726,448	$34,095,882	$78,029,133	$131,642,000	$204,592,593
% Increase		64.50%	128.85%	68.71%	55.42%
Staffing	80	146	218	373	465
% Increase	-	82.58%	49.25%	71.10%	24.66%

© 2004 All Rights Reserved

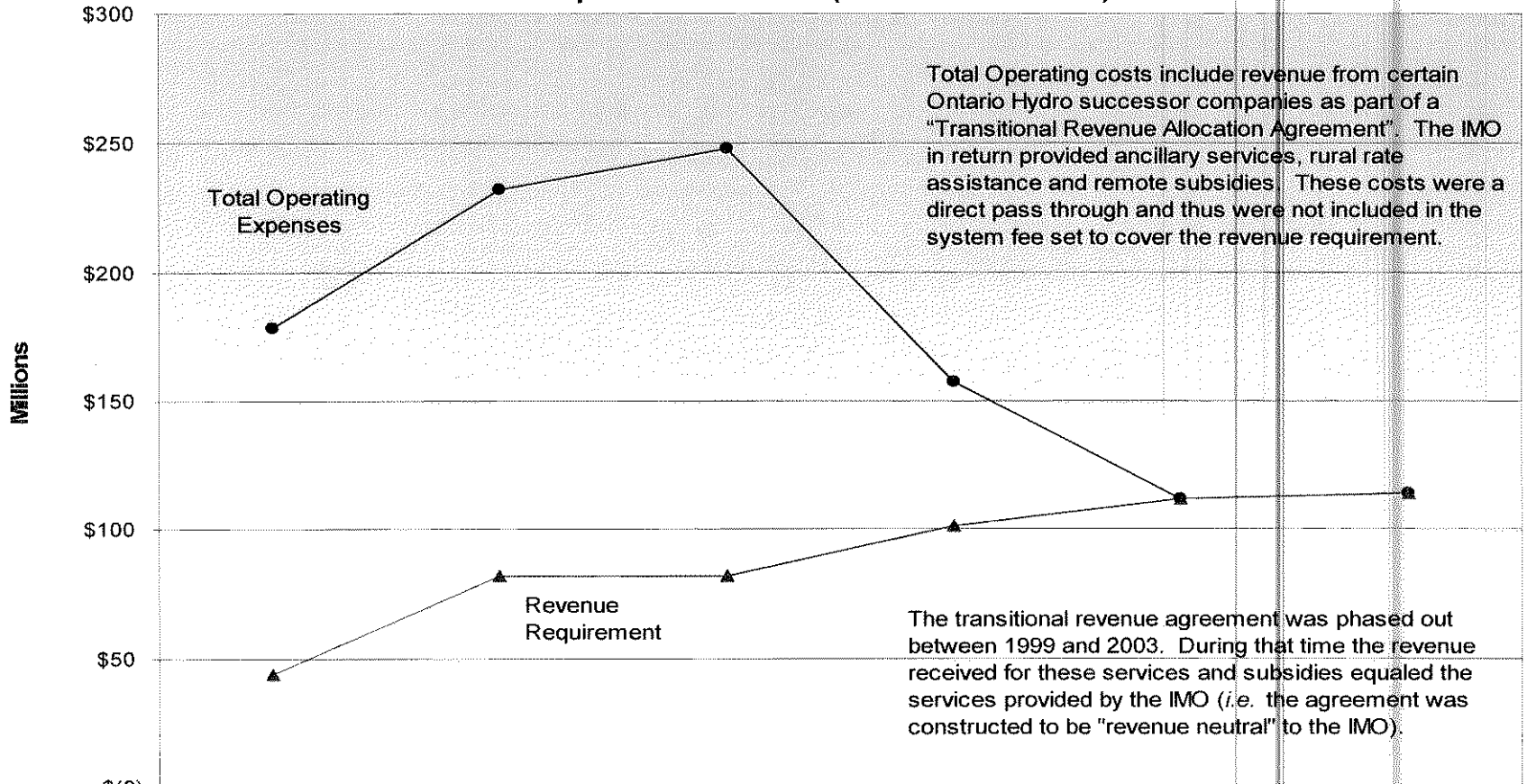
ISO New England Annual Operational Costs (2003 Dollars)



	1998	1999	2000	2001	2002	2003	2004
Op Costs:	$27,685,000	$34,295,000	$47,324,487	$64,451,126	$67,280,297	$102,924,000	$118,965,624
% Change:		23.88%	28.45%	36.19%	4.39%	52.98%	15.59%
Staffing:	180	224	271	314	350	366	402
% Increase:	-	24.44%	20.98%	15.87%	11.46%	4.57%	9.70%

© 2004 All Rights Reserved

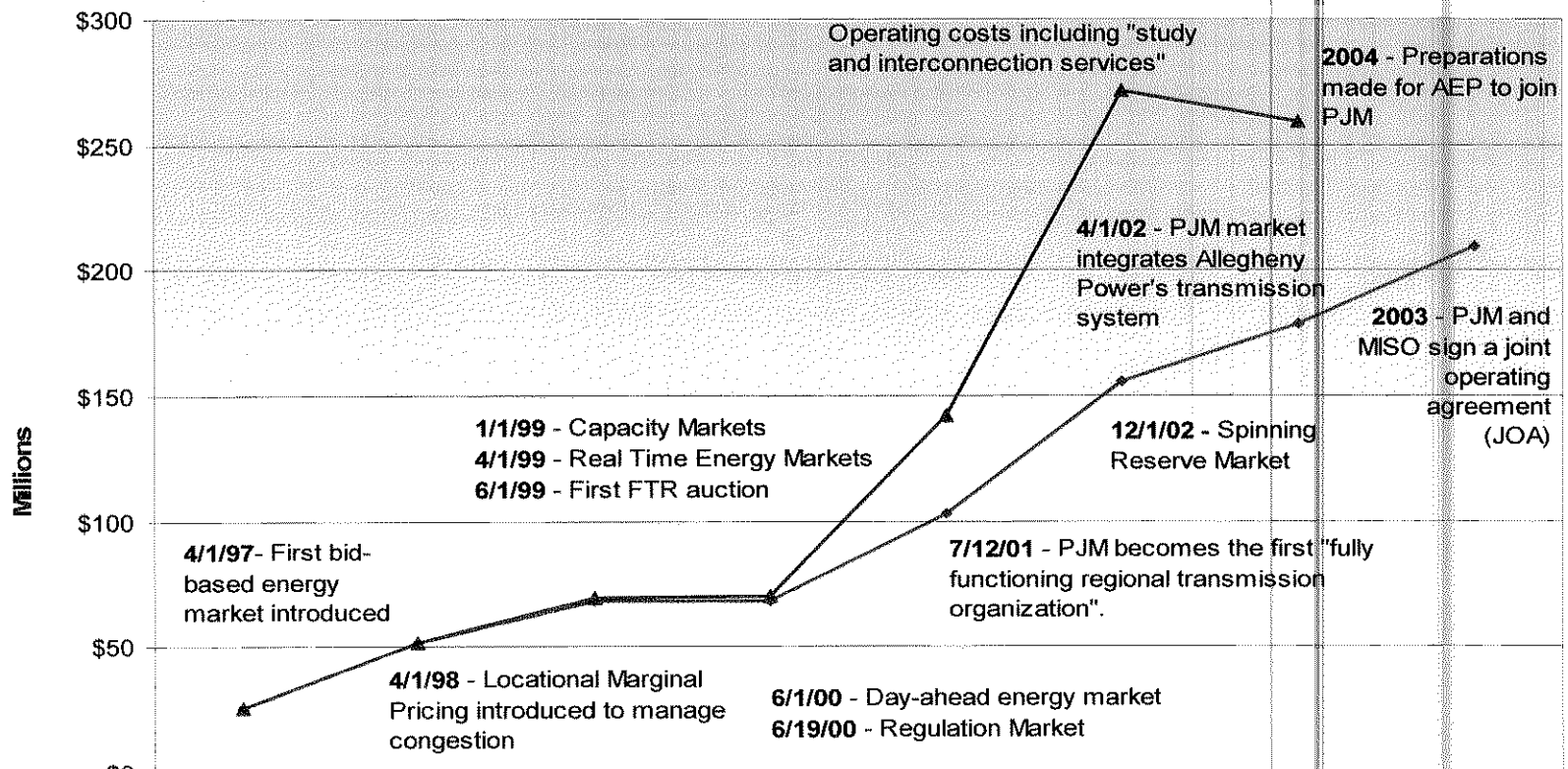
Ontario Independent Market Operator (IMO)
Annual Operational Costs (2003 U.S. Dollars)



	1999	2000	2001	2002	2003	2004
Total Expense	$178,083,278	$231,935,946	$248,209,497	$157,304,028	$111,597,840	$114,060,370
Revenue Req.	$43,847,951	$81,666,325	$81,943,185	$101,321,760	$111,597,840	$114,060,370
Staffing		373	390	408	407	424
% Change		86.25%	0.34%	23.65%	10.14%	2.21%

© 2004 All Rights Reserved

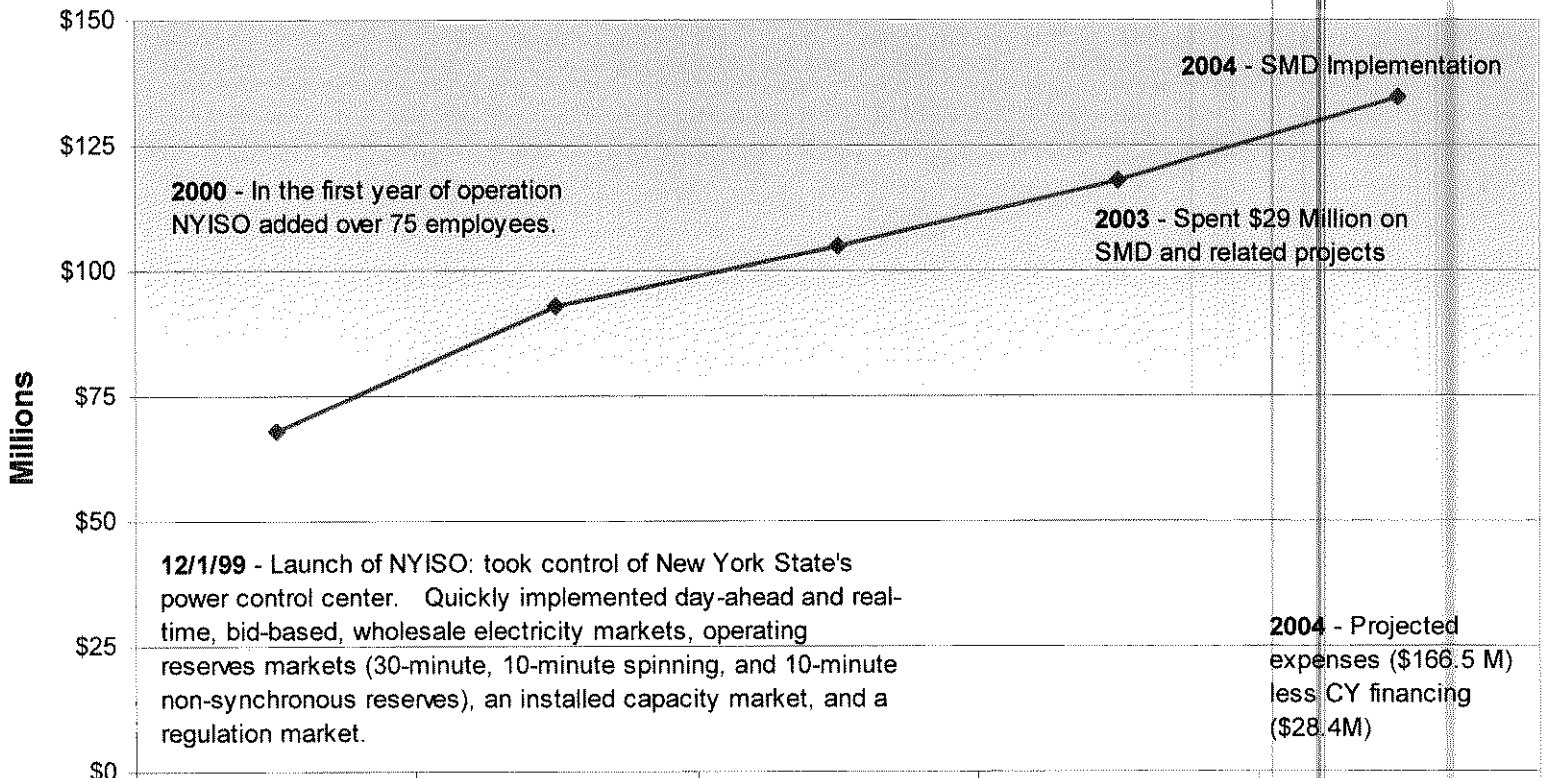
PJM Annual Operating Costs (2003 Dollars)



	1997	1998	1999	2000	2001	2002	2003	2004
Op Costs	$25,240,977	$51,290,561	$68,405,894	$68,188,810	$103,196,856	$155,627,431	$178,492,173	$209,463,845
% Increase		103.20%	33.37%	-0.32%	51.34%	50.81%	14.69%	17.35%
W/ S&I Services	$25,240,977	$51,290,561	$69,473,280	$70,271,237	$141,865,885	$271,411,002	$259,103,173	
Staffing		238	288	332	390	448	493	undisclosed
% Increase			21.0%	15.3%	17.5%	14.9%	10.0%	

© 2004 All Rights Reserved

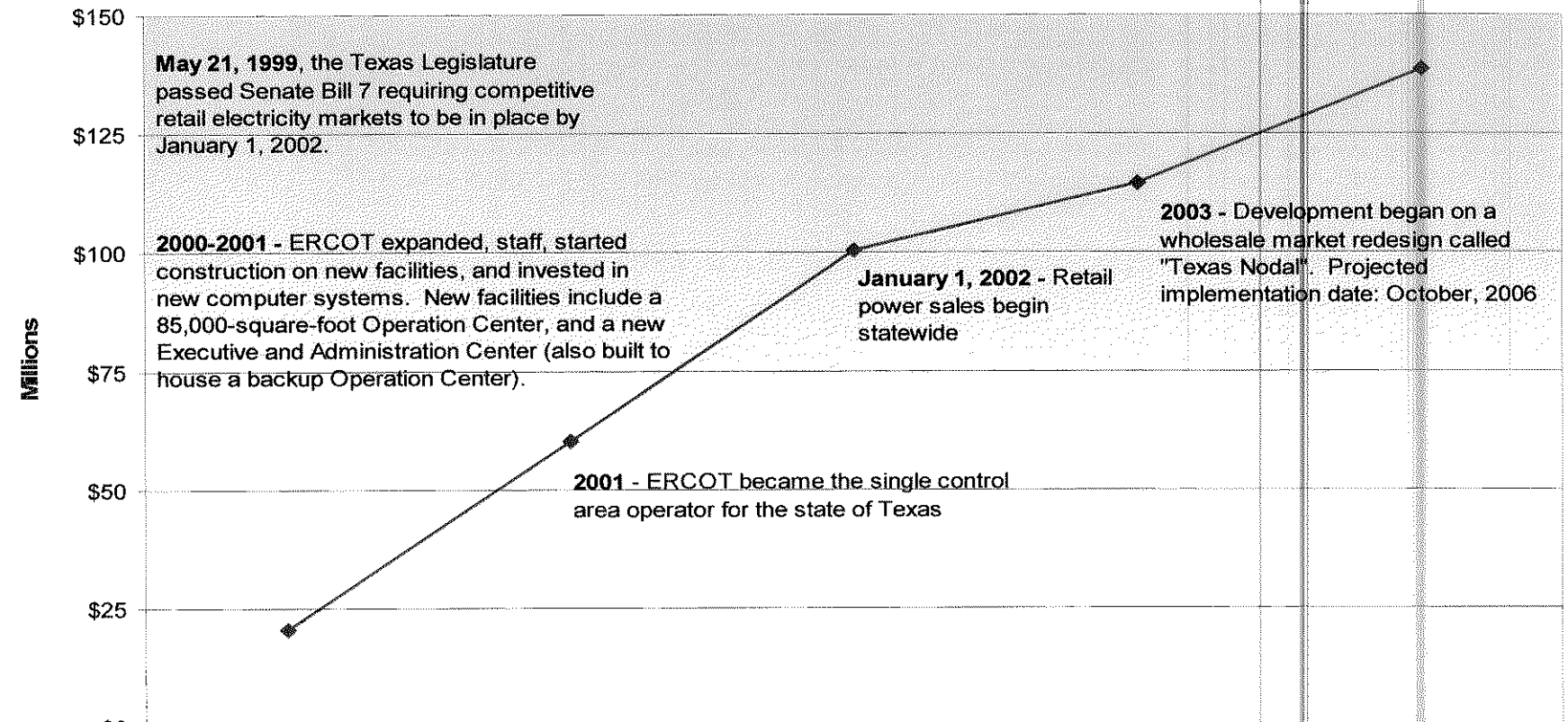
New York ISO Annual Operating Costs (2003 dollars)



	2000	2001	2002	2003	2004
Op Costs	$67,669,514	$92,660,733	$104,718,914	$117,819,269	$134,543,986
% Change		36.93%	13.01%	12.51%	14.20%
Staffing	220	282	312	358	392
% Increase	52.8%	28.2%	10.6%	14.7%	9.5%

© 2004 All Rights Reserved

ERCOT Annual Operating Expense



	2000	2001	2002	2003	2004
O&M	$20,526,635	$60,137,302	$100,413,764	$114,413,000	$138,589,841
% Increase		192.97%	66.97%	13.94%	21.13%
FTE	50	240	296	380	530
% Increase		380.00%	23.33%	28.38%	39.47%

© 2004 All Rights Reserved

Data Sources:

PJM:
O&M, Amortization, Depreciation, and Interest Expense: 1997-2003 (FERC Form 1 submissions); 2004 (*Approved 2004 Budget and Service Category Rates*, 10/28/2003).
Annual Energy: 1997-1999 (*1999 Annual Report on Operations*); 2000 (*2000 Annual Report on Operations*); 2001 (*2001 Annual Report on Operations*); 2002-2003 (Corresponding *Annual Reports*); 2004 (*Approved 2004 Budget and Service Category Rates*, 10/28/2003).
Staffing Levels: 1998-2001 (FERC Form 1 submissions); 2002 (448 employees as of 9/30/2002 noted in PJM's 2002 3rd Quarter Financial Statement); 2003 (*NYISO 2003 Budget Review* for the Budget, Performance, and Standards Committee, 9/30/2002).
Start-up Costs: PJM staffers indicated that they have not calculated their overall start-up costs. Estimate provided by the *Ontario IMO 2001-2003 Business Plan*, 11/13/2000, pg. 41.

New York ISO:
O&M, Amortization, Depreciation, and Interest Expense: 2000-2003 (FERC Form 1 submissions); 2004 (*NYISO 2004 Budget Report* for the Budget, Standards and Performance Subcommittee, 11/12/2003).
Annual Energy: 2000-2002 (NYISO 2003 *Gold Book - Load and Capacity Data*); 2003-2004 (Backed into using revenue requirements and $/MWh rates in *NYISO 2004 Budget Report*, 11/12/2003).
Staffing Levels: 2000 (*Annual Report*); 2001 (NYISO *Budget vs. Actual Results*, February 2002); 2002 (2003 *Budget Review*, 9/30/2002); 2003-2004 (*2004 Budget Overview*, 9/26/2003).
Start-up Costs: *Tabors Caramanis RTO West Cost Benefit Study*, 3/11/2002.

ISO New England:
O&M, Amortization, Depreciation, and Interest Expense: 1998-2002 (Corresponding *Annual Reports*); 2003 (*2003 Final Audited Financial Statement*, 3/3/2004); 2004 (*ISO-NE March Forecast for End of Year 2004*, March 2004).
Annual Energy: 1998-2004 (1999-2004 Annual *Capacity, Energy, Loads, and Transmission (CELT) Reports*, Note: 2004 is a forecast).

© 2004 All Rights Reserved

ISO New England Cont.

Staffing Levels: 1998-2001 (FERC Form 1 Submissions); 2002 (*Annual Report*); 2003 (NYISO *2003 Budget Review*, 9/30/2002); 2004 (*ISO-NE March Forecast for End of Year 2004,* March 2004, Note: Projected FTE).
Start-up Costs: FERC order "Accepting for Filing and Suspending Cost Recovery Proposal, Subject to Refund and Establishing Hearing", Docket No. ER99-4235-000, 10/13/1999.

California ISO:

O&M, Amortization, Depreciation, and Interest Expense: 1998-2002 (FERC Form 1 submissions); 2003 (*December Monthly Financial Report*, 12/31/2003 Note: Actual 2003 numbers - unaudited); 2004 (*Proposed FY2004 Operating & Maintenance Budget and Capital Budget*, 9/18/03).
Annual Energy: 1998 (*2000 Annual Report on Market Issues and Performance*, November 2001); 1999-2001 (*2002 Annual Report on Market Issues and Performance,* April 2003); 2002-2003 (*2003 Market Performance Review* from the Office of Market Analysis, April 2004); 2004 (*Proposed FY2004 Operating & Maintenance Budget and Capital Budget*, 9/18/03).
Staffing Levels: 2000-2001 (FERC Form 1 submissions); 2002 (*Proposed FY 2003 Budget*, 10/16/2002, Note: "revised and approved staffing" level); 2003 (*December Monthly Financial Report*, 12/31/2003); 2004 (*Proposed FY2004 Operating & Maintenance Budget and Capital Budget*, 9/18/2003 Note: projected FTE).
Start-up Costs: *Financing Plan Execution*, 4/23/1998.

ERCOT:

O&M, Amortization, Depreciation, and Interest Expense: 2000-2003 (*2003 Annual Report*); 2004 (2004 Texas PUC rate filing (Docket # 28832)).
Annual Energy: 2000-2004 (2004 Texas PUC rate filing - Docket # 28832, Note: 2001-2002 are actuals, 2003 is part actual and part budgeted and 2004 is budgeted).
Staffing Levels: 2000, 2001, 2003 (*2003 Annual Report*); 2002 (Estimate based on rate filing information); 2004 (2004 Texas PUC rate filing (Docket # 28832)).
Start-up costs: Start-up Costs: *Tabors Caramanis RTO West Cost Benefit Study*, March 11, 2002.

© 2004 All Rights Reserved

Midwest ISO:
O&M costs, Amortization, Depreciation, and Interest: 2000-2003 (Corresponding *Annual Reports*); 2004 (*Updated 2004 Budget Presentation*, 3/18/2004, Note: original budget from MISO *Budget Advisory Committee Presentation*, 12/10/03).
Annual Energy: MISO does not collect or compute annual energy demand at this time. Estimates of MISO annual demand calculated using FERC Form 1 submissions of MISO membership.
Staffing Levels: 2000 (*MISO Order 2000 Compliance Filing (RT01-87-000);* 1/16/2001); 2001, 2002, 2004 (*2004 Budget Advisory Committee Presentation*, 12/10/2003.); 2003 (*2003 Annual Report*).
Start-up Costs: MISO *2000 Annual Report.*

Ontario IMO:
O&M, Amortization, Depreciation, and Interest Expense: 1999-2002 (Corresponding *Annual Reports*); 2003 (*2003 Final Audited Financial Statement,* 1/12/04); 2004 (*IMO Business Plan 2004-2006 Financial Overview*, 9/30/2003).
Annual Energy: Demand Overview section of Ontario IMO's webpage: http://www.theimo.com/imoweb/media/md_demand.asp
Staffing Levels: 2000, 2002 (*IMO Business Plan 2001-2003*, 11/13/2000); 2002 (*Annual Report*); 2003-2004 (*IMO Business Plan 2004-2006 Financial Overview*, 9/30/2003 Note: 2003 is projected, 2004 is budgeted).
Start-up Costs: *Ontario IMO 2001-2003 Business Plan*, 11/13/2000.

© 2004 All Rights Reserved