Oregon

Theodore R. Kulongoski, Governor

Public Utility Commission
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March 15, 2005

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 2148
SALEM OR 97308-2148

RE: **OPUC Docket No. UE 167** - In the Matter of IDAHO POWER COMPANY'S Application for General Rate Increase in the Company's Oregon Annual Revenues of $4,418, 908, or 17.52 Percent Overall

Enclosed for filing in the above-captioned docket is the Public Utility Commission's UE 167 Direct Testimony. This document is being filed by electronic mail with the PUC Filing Center.

Judy Ogilvie

Judy Ogilvie
Regulatory Operations Division
Filing on Behalf of Public Utility Commission Staff
(503) 378-5763
Email: judy.ogilvie@state.or.us

PUBLIC UTILITY COMMISSION
OF
OREGON

UE 167

STAFF TESTIMONY

OF

CARLA OWINGS
MAURY GALBRAITH

In the Matter of IDAHO POWER COMPANY'S Application for General Rate Increase in the Company's Oregon Annual Revenues of $4,418, 908, or 17.52 Percent Overall

March 15, 2005

CASE: UE 167
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Direct Testimony

March 15, 2005

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Carla Owings. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551. I am a Senior Revenue Requirements Analyst for Electric & Natural Gas Revenue Requirements in the Utility Program of the Public Utility Commission of Oregon.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/101, Owings/1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. As the revenue requirement summary witness for the Commission staff (Staff) in this proceeding, I am generally familiar with the adjustments to Idaho Power Company's (Idaho Power or Company) filing in this docket sponsored by myself and other Staff analysts. On February 24, 2005, the Company met with the parties to this docket: Staff, Oregon Industrial Customers of Idaho Power and Citizen's Utility Board, in a Settlement Conference. As a result of that discussion, the parties entered into an agreement regarding Staff's proposed adjustments with the exception of Item S-2, Net Power Supply (*See Staff/102, Owings/2, Item S-2*). Staff Witness Maury Galbraith will address the Power Supply Costs in his direct testimony at Staff/200, Galbraith.

Q. WERE ANY OTHER ISSUES AGREED UPON AS A RESULT OF THE SETTLEMENT DISCUSSIONS?

A. Yes. The stipulated agreement currently being prepared by the Company will include provisions between the parties regarding the allocation of uncollectible expenses as they relate to rate design (*See Item S-11, at Staff/102, Owings/4*), the Company's proposal to add a $20 Service Establishment Charge and five very specific audit recommendations (*See Item S-12, at Staff/102, Owings/4*).

Q. IS A STIPULATION BEING PREPARED AS A RESULT OF THE SETTLEMENT DISCUSSIONS?

A. Yes. A stipulation, with supporting joint testimony, is forthcoming.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I have prepared Exhibit Staff/102, consisting of 10 pages. This exhibit contains tables summarizing the agreed-upon adjustments for Idaho Power's revenue requirements in this docket.

Q. PLEASE DESCRIBE THE INFORMATION IN EXHIBIT STAFF/102.

A. Exhibit Staff/102 contains five separate elements which together summarizes the agreed-upon revenue requirement adjustments for UE 167, plus Staff's proposed adjustment for Net Power Supply (*See Staff/102, Owings/2, Issue S-2)*:

1. Page 1 shows a summary of the adjustments to Idaho Power's system test year period numbers per the Company's application, as well as a summary of the adjustments to the Oregon allocated portion of the test year period (*See Idaho Power/24, Obenchain/1*).

2. Pages 2 through 5 provide a brief narrative description of the adjustments, as well as a summary of the audit recommendations and adjustment to the rate design for uncollectible expenses, as discussed above in this Testimony. A list of the individuals sponsoring revenue requirement adjustments and policy recommendations in UE 167 is shown on Page 5 of Staff/102.

3. Pages 6 and 7 of Exhibit 102 are revenue requirement schedules for the adjustments in this docket. Page 6, col. (4) shows the composite of the adjustments

to the test year data contained in Idaho Power's application. Column (4) shows the changes for Idaho Power's revenue requirements of a negative $209 million, or a .83 percent (.83%) reduction in operating revenues from existing rates (*See Staff/102, Owings/6, line 1, column 4, Required Change for Reasonable Return)*. Staff believes this reduction is required for the Company to achieve a reasonable rate of return. Page 7 contains the summary income tax calculations for the adjustments to the revenue requirements.

4. Page 8 shows the capital structure and revenue sensitive costs that have been used to calculate revenue requirement in this case.

5. Pages 9 and 10 show the adjustments. Page 9 shows each adjustment with the revenue requirement effect of each adjustment on line 41. Page 10 shows the income tax calculation for each adjustment.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 167
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

March 15, 2005

WITNESS QUALIFICATION STATEMENT

NAME:	Carla M. Owings
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst/Revenue Requirement/Rates and Regulation
ADDRESS:	550 Capitol Street NE Suite 215, Salem, Oregon 97301-2115.
EDUCATION:	Professional Accounting Degree Trend College of Business 1983
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since April of 2001. I am the Senior Utility Analyst for revenue requirement for the Rates and Regulation Division of the Utility Program. Current responsibilities include leading research and providing technical support on a wide range of policy issues for electric, telecommunications, and gas utilities. From September 1994 to April 2001, I worked for the Oregon Department of Revenue as a Senior Industrial/Utility Appraiser. I was responsible for the valuation of large industrial properties as well as utility companies throughout the State of Oregon.
OTHER EXPERIENCE:	I received my certification from the National Association of State Boards of Accountancy in the Principles of Public Utilities Operations and Management in March of 1997. I have attended the Institute of Public Utilities sponsored by the National Association of Regulatory Utility Commissioners at Michigan State University in August of 2002 and the College of Business Administration and Economics at New Mexico State University's Center for Public Utilities in May of 2004.

CASE:	UE 167
WITNESS:	Carla Owings

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support of
Direct Testimony

March 15, 2005

IDAHO POWER
UE 167
STAFF ADJUSTED RESULTS
YEAR ENDING DECEMBER 2003

ADJUSTED RESULTS

	DESCRIPTION	SYSTEM PER APPLICATION	OREGON PER APPLICATION	PERCENT OREGON ALLOCATED	SYSTEM ADJUSTED RESULTS	OREGON ADJUSTED RESULTS
1	**Rate of Return Under Present Rates**					
2	**Total Combined Rate Base**	1,693,060,930	81,791,447	4.831%	1,660,428,902	80,215,000
3						
4	**Revenues**					
5	Sales Revenues	509,181,668	25,220,299	4.953%	569,103,685	28,188,299
6	Other Operating Revenues	42,464,061	1,855,258	4.369%	114,307,060	4,994,084
7	**Total Operating Revenues**	551,645,729	27,075,557	4.908%	683,410,745	33,182,383
8						
9	**Operating Expenses**					
10	Operation & Maintenance Expenses	394,003,896	19,130,997	4.856%	385,086,300	18,698,000
11	Depreciation Expense	90,083,854	4,506,077	5.002%	89,863,946	4,495,077
12	Amortization Expense	9,886,473	488,509	4.941%	9,886,473	488,509
13	Taxes other than Income	21,746,762	1,494,994	6.875%	21,732,216	1,493,994
14	Provision for Deferred Income Taxes	2,799,569	104,840	3.745%	2,803,842	105,000
15	Investment Tax Credit Adjustment	(397,388)	(14,882)	3.745%	400,539	15,000
16	Federal Income Taxes	16,360,882	612,690	3.745%	46,858,631	1,754,784
17	State Income Taxes	2,260,272	84,644	3.745%	8,134,650	304,631
18	**Total Operating Expenses**	536,744,320	26,407,869	4.920%	564,766,596	27,354,995
19						
20	**Operating Income**					
21	Operating Income	81,484,118	3,783,514	4.643%	126,141,660	5,857,077
22	Add: IERCO Operating Income	6,921,602	341,811	4.938%	6,921,602	341,811
23	**Consolidated Operating Income**	88,405,720	4,125,325	4.666%	133,063,262	6,198,888
24	**Rate of Return at present rates**	5.22%	5.04%		8.01%	7.73%
25						
26	**Development of Revenue Requirement**					
27	Rate of Return @ required 11.20 ROE	8.334%	8.334%		7.728%	7.728%
28						
29	Return at claimed rate of return	141,099,698	6,816,499	4.831%	128,317,946	6,199,015
30	Earnings Deficiency	52,693,978	2,691,174	5.107%	(4,745,316)	(127)
31						
32	Net to Gross Multiplier	1.642	1.642		1.648	1.648
33	Revenue Deficiency	86,523,512	4,418,908	5.107%	(7,822,180)	(209)
34						
35	Firm Juristitional Revenues	515,869,558	25,220,299	4.889%	515,869,558	25,220,299
36	Percent Increase Required	16.77%	17.52%		-1.52%	-0.83%
37						
38	Sales and Wheeling Required	602,393,070	29,639,207	4.920%	508,047,378	25,220,090

IDAHO POWER
UE 167
STAFF ISSUE SUMMARY SHEET
TEST PERIOD ENDING DECEMBER 2003
($000)

Item	Staff	Issue	Revenue Requirement Effect
		Revenue Requirement on the Company's Filed Results **Proposed Staff Adjustments**	**$4,419**
S-0	TM/BC	Rate of Return -ISSUE RESOLVED AS RESULT OF STIPULATION	**(813)**
S-00	CO	Net to Gross Factor - ISSUE RESOLVED AS A RESULT OF STIPULATION	**14**
S-1	CO	Known & Measurable Changes to Rate Base - ISSUE RESOLVED AS A RESULT OF STIPULATION	**(23)**
S-2	MG/BW	Net Power Supply Idaho Power uses the AURORA model to estimate competitive market electricity prices. The estimated prices are significantly lower than actual market electricity prices known at the time of the UE 167 filing. Staff recommends adjustments to surplus sales and purchased power based on using market electricity prices more representative of the period rates will be in effect.	**(3,116)**
S-3	CO	Cloud Seeding Costs - ISSUE RESOLVED AS A RESULT OF STIPULATION	**(52)**
S-4	MD	Non-Labor A & G Expenses - ISSUE RESOLVED AS A RESULT OF STIPULATION	**(187)**

IDAHO POWER
UE 167
STAFF ISSUE SUMMARY SHEET
TEST PERIOD ENDING DECEMBER 2003
($000)

Item	Staff	Issue	Revenue Requirement Effect
S-5	LK	Employee Incentive Pay - ISSUE RESOLVED AS A RESULT OF STIPULATION	(287)
S-6	LK	Payroll Salary Structure - ISSUE RESOLVED AS A RESULT OF STIPULATION	0
S-7	LK	Wage & Salary Adjustment - ISSUE RESOLVED AS A RESULT OF STIPULATION	(32)
S-8	CO	Hells Canyon Complex Legal Costs - ISSUE RESOLVED AS A RESULT OF STIPULATION	(4)
S-9	CO	Rate Base Additions Annualized - ISSUE RESOLVED AS A RESULT OF STIPULATION	(34)
S-10	MD	Prepaid Pension Expense - ISSUE RESOLVED AS A RESULT OF STIPULATION	(94)
S*		Rounding	0
		TOTAL	**(4,628)**
		INDICATED REVENUE REQUIREMENT:	**($209)**

IDAHO POWER
UE 167
STAFF ISSUE SUMMARY SHEET
TEST PERIOD ENDING DECEMBER 2003
($000)

Item	Staff	Issue	Revenue Requirement Effect
		Other Issues	
S-11	JF/JB	Marginal Cost Adjustment - ISSUE RESOLVED AS A RESULT OF STIPULATION Adjust marginal costs as used in Idaho Power's marginal cost study. Reallocate uncollectible expenses proportionate to a four-year average between the customer classes. Proposal to add a $20 Service Establishment Charge as described at Idaho Power/Exhibit 34T, Bowman/Pages 6-8 to be waived.	
S-12	MD	Audit Recommendations - ISSUES RESOLVED AS A RESULT OF STIPULTATION 1. Pursuant to ORS 757.495 and OAR 860-027-0040, IPC should file an application for approval of the service agreement for those administrative services furnished to IPC by affiliates, and for services provided by IPC to affiliates. IPC was requested to file within sixty days of the receipt of the Idaho Power Audit Report dated December 8, 2004. (Audit Recommendation) 2. Pursuant to OAR 860-027-0041, IPC should file an informational filing concerning the construction services provided to IDACOMM. (Audit Recommendation) 3. Pursuant to ORS 757.495 and OAR 860-027-0040, IPC should file an application for approval of the short-term borrowing from its affiliate, Idaho Energy Resources Co. (IERCO). (Audit Recommendation) 4. IPC shall file pursuant to ORS 757.480 and OAR 860-027-0025, an application for Commission approval of two property sales (Boise Bench Transmission Station Land Sale (2001), State Street Office Sale (2001)) and any other property sale that was of a value in excess of $100,000. (Audit Recommendation). 5. IPC should improve its accounting processes to properly classify lobbying expenses to non-utility accounts when the expenses are initially recorded on its books. (Audit Recommendation)	

IDAHO POWER
UE 167
STAFF ISSUE SUMMARY SHEET
TEST PERIOD ENDING DECEMBER 2003
($000)

Item	Staff	Issue	Revenue Requirement Effect
	Staff Witnesses:		
JB		Jack Breen	378-5942
BC		Bryan Conway	378-6200
MD		Michael Dougherty	378-3623
JF		Janet Fairchild	
MG		Maury Galbraith	378-6667
LK		Lynn Kittilson	378-6116
TM		Thomas Morgan	378-4629
CO		Carla Owings	378-6629
BW		Bill Wordley	378-5264

IDAHO POWER
UE 167
REVENUE REQUIREMENT MODEL
TEST PERIOD ENDING DECEMBER 2003
($000)

	SUMMARY SHEET	2003 Results Per Company Filing (1)	Adjustments (2)	2003 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1	**Operating Revenues**	$25,220	$3,177	$28,397	($209)	$28,188
2	Retail Sales	3,116	0	3,116	0	3,116
3	Wholesale Sales	1,855	23	1,878	0	1,878
4	Other Revenues	$30,191	$3,200	$33,391	($209)	$33,182
5	**Total Operating Revenues**					
6	**Operating Expenses**	$6,434	$0	$6,434	$0	$6,434
7	Steam Production	1,190	(49)	1,141	0	1,141
8	Hydro Production	3,599	68	3,667	0	3,667
9	Other Power Supply	883	0	883	0	883
10	Transmission	2,646	0	2,646	0	2,646
11	Distribution	838	0	838	0	838
12	Customer Accounting	233	0	233	0	**233**
13	Customer Service & Info	0	0	0	0	0
14	Sales	3,308	(452)	2,856	0	2,856
15	Administrative and General	$19,131	($433)	$18,698	$0	$18,698
16	**Total Operation & Maintenance**	$4,506	($11)	$4,495	$0	$4,495
17	Depreciation	489	0	489	0	489
18	Amortization	1,495	0	1,495	(1)	1,494
19	Taxes Other than Income	788	1,443	2,231	(81)	2,150
20	Income Taxes	(342)	0	(342)	0	(342)
21	Miscellaneous Revenue and Expense	$26,066	$999	$27,065	($82)	$26,983
22	**Total Operating Expenses**	$4,125	$2,201	$6,326	($127)	$6,199
23	**Net Operating Revenues**					
24	**Average Rate Base**	$157,928	($798)	$157,130	$0	$157,130
25	Electric Plant in Service	(68,493)	44	(68,449)	0	(68,449)
26	Accumulated Depreciation & Amortization	(11,456)	0	(11,456)	0	(11,456)
27	Accumulated Deferred Income Taxes		0	0	0	0
28	Accumulated Deferred Inv. Tax Credit	77,979	($754)	$77,225	$0	$77,225
29	**Net Utility Plant**	0	0	0	0	0
30	Plant Held for Future Use	0	0	0	0	0
31	Acquisition Adjustments	765	38	803	(1)	802
32	Working Capital	324	0	324	0	324
33	Fuel Stock	1,020	0	1,020	0	1,020
34	Materials & Supplies	(53)	0	(53)	0	(53)
35	Customer Advances for Construction		0	0	0	0
36	Weatherization Loans	860	(860)	0	0	0
37	Prepayments	186	0	186	0	186
38	Misc. Deferred Debits	711	0	711	0	711
39	Misc. Rate Base Additions/(Deductions)	$81,792	($1,576)	$80,216	($1)	$80,215
40	**Total Average Rate Base**	5.04%		7.89%		7.73%
41	**Rate of Return**	4.16%		10.34%		10.00%
42	**Implied Return on Equity**	4.16%		10.57%		10.00%

3/14/2005

IDAHO POWER
UE 167
OREGON ALLOCATED RESULTS OF OPERATION
TEST PERIOD ENDING DECEMBER 2003
($000)

		Income Tax Calculations	2003 Per Company Filing (1)	Adjustments (2)	2003 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1		Book Revenues +IERCO Income	$30,514	$3,200	$33,714	($209)	$33,502
2		Book Expenses Other than Depreciation	20,626	(433)	20,193	(1)	20,189
3		State Tax Depreciation	5,008	(11)	4,997	0	4,997
4		Interest	2,960	(46)	2,914	0	2,914
5	Less:	Schedule M Differences	(46)	0	(46)	0	(46)
6		State Taxable Income	$1,966	$3,690	$5,657	($208)	$5,449
7		State Income Tax	$85	$233	$318	($13)	$305
8		State Tax Credits	0	0	0	0	0
9		Net State Income Tax	$85	$233	$318	($13)	$305
10		IERCO INCOME Adjustment	$323	$0	$323	$0	$323
11	Plus:	Other Schedule M Differences	64	0	64	0	64
12		Federal Taxable Income	$1,579	$3,457	$5,037	($195)	$4,842
13		Federal Tax @ 35%	$553	$1,210	$1,763	($68)	$1,695
14		Federal Tax Credits	0	0	0	0	0
15		Current Federal Tax	$553	$1,210	$1,763	($68)	$1,695
16		ITC Adjustment	$0	$0	$0	$0	$0
17		Prior Year Defficiency	60	0	60	0	60
18		Restoration	15	0	15	0	15
19		Total ITC Adjustment	$45	$0	$45	$0	$45
20		Provision for Deferred Taxes	$105	$0	$105	$0	$105
21		Total Income Tax	$787	$1,443	$2,230	($81)	$2,149

IDAHO POWER
UE 167
OREGON ALLOCATED RESULTS OF OPERATIONS
TEST PERIOD ENDING DECEMBER 2003
($000)

REVENUE SENSITIVE COSTS

Revenues	1.00000
Operating Revenue Deductions	
Uncollectible Accounts	0.00000
Taxes Other - Franchise	0.00394
- Other	0.00000
- Resource supplier	0.00000
State Taxable Income	0.99606
State Income Tax	0.06275
Federal Taxable Income	0.93331
Federal Income Tax @ 35%	0.32666
ITC	0.00000
Current FIT	0.32666
Other	0.00000
Total Excise Taxes	0.38941
Total Revenue Sensitive Costs	0.39335
Utility Operating Income	0.60665
Net-to-Gross Factor	**1.648**

COST OF CAPITAL - STAFF

	% of CAPITAL	COST	WEIGHTED COST
Long Term Debt	51.06%	5.75%	2.94%
Preferred Stock	2.97%	6.54%	0.19%
Common Equity	45.97%	10.00%	4.60%
Total	100.00%		**7.73%**

IDAHO POWER
UE 167
STAFF ADJUSTMENTS TO OREGON ALLOCATED RESULTS
TEST PERIOD ENDING DECEMBER 2003
($000)

	Staff Adjustments	Rate Base Adjust to K & M changes (S-1)	Net Power Supply adj. (S-2)	Cloud Seeding Costs (S-3)	Non-labor A & G Expenses (S-4)	Employee Incentive Pay K & M (S-5)	3% Payroll Salary increase K & M (S-6)	Wage & Salary Adjustment (S-7)	Hells Canyon Legal Costs (S-8)	Annualized Rate Base Additions (S-9)	Prepaid Pension Expense (S-10)	**Total Adjustments (Base Rates)**
1	**Operating Revenues**											
2	Retail Sales	0	3,177	0	0	0	0	0	0	0	0	3,177
3	Wholesale Sales	0	0	0	0	0	0	0	0	0	0	0
4	Other Revenues	23	0	0	0	0	0	0	0	0	0	23
5	**Total Operating Revenues**	**$23**	**$3,177**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$3,200**
6	**Operating Expenses**											
7	Steam Production	0	0	0	0	0	0	0	0	0	0	0
8	Hydro Production	0	0	(49)	0	0	0	0	0	0	0	(49)
9	Other Power Supply	0	68	0	0	0	0	0	0	0	0	68
10	Transmission	0	0	0	0	0	0	0	0	0	0	0
11	Distribution	0	0	0	0	0	0	0	0	0	0	0
12	Customer Accounting	0	0	0	0	0	0	0	0	0	0	0
13	Customer Service & Info	0	0	0	0	0	0	0	0	0	0	0
14	Sales	0	0	0	0	0	0	0	0	0	0	0
15	Administrative and General	0	0	0	(186)	(234)	0	(32)	0	0	0	(452)
16	**Total Operation & Maintenance**	**$0**	**$68**	**($49)**	**($186)**	**($234)**	**$0**	**($32)**	**$0**	**$0**	**$0**	**($433)**
17	Depreciation	0	0	0	0	(11)	0	0	0	0	0	(11)
18	Amortization	0	0	0	0	0	0	0	0	0	0	0
19	Taxes Other than Income	0	0	0	0	0	0	0	0	0	0	0
20	Income Taxes	9	1,215	19	73	100	0	13	0	4	10	1,443
21	Miscellaneous Revenue and Expense	0	0	0	0	0	0	0	0	0	0	0
22	**Total Operating Expenses**	9	1,283	(30)	(113)	(145)	0	(19)	0	4	10	999
23	**Net Operating Revenues**	**$14**	**$1,894**	**$30**	**$113**	**$145**	**$0**	**$19**	**$0**	**($4)**	**($10)**	**$2,201**
24	**Average Rate Base**											
25	Electric Plant in Service	0	0	(25)	0	(374)		(5)	(29)	(365)	0	(798)
26	Accumulated Depreciation & Amortization	0	0	0	0	0	0	0	0	44	0	44
27	Accumulated Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
28	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0	0	0	0	0
29	**Net Utility Plant**	**$0**	**$0**	**($25)**	**$0**	**($374)**	**$0**	**($5)**	**($29)**	**($321)**	**$0**	**($754)**
30	Plant Held for Future Use	0	0	0	0	0	0	0	0	0	0	0
31	Acquisition Adjustments	0	0	0	0	0	0	0	0	0	0	0
32	Working Capital	0	51	(1)	(5)	(6)	0	(1)	0	0	0	38
33	Fuel Stock	0	0	0	0	0	0	0	0	0	0	0
34	Materials & Supplies	0	0	0	0	0	0	0	0	0	0	0
35	Customer Advances for Construction	0	0	0	0	0	0	0	0	0	0	0
36	Weatherization Loans	0	0	0	0	0	0	0	0	0	0	0
37	Prepayments	0	0	0	0	0	0	0	0	0	(860)	(860)
38	Misc. Deferred Debits	0	0	0	0	0	0	0	0	0	0	0
39	Misc. Rate Base Additions/(Deductions)	0	0	0	0	0	0	0	0	0	0	0
40	**Total Average Rate Base**	**$0**	**$51**	**($26)**	**($5)**	**($380)**	**$0**	**($6)**	**($29)**	**($321)**	**($860)**	**($1,576)**
41	**Revenue Requirement Effect**	**($23)**	**($3,116)**	**($52)**	**($187)**	**($287)**	**$0**	**($32)**	**($4)**	**($34)**	**($94)**	**($3,829)**

3/14/2005

STAFF ADJUSTMENTS TO OREGON ALLOCATED RESULTS
TEST PERIOD ENDING DECEMBER 2003
($000s)

	Income Tax Calculations	Rate Base Adjust to K & M changes (S-1)	0 Net Power Supply adj. (S-2)	Cloud Seeding Costs (S-3)	Non-labor A & G Expenses (S-4)	Employee Incentive Pay K & M (S-5)	3% Payroll Salary increase K & M (S-6)	Wage & Salary Adjustment (S-7)	Hells Canyon Legal Costs (S-8)	Annualized Rate Base Additions (S-9)	Prepaid Pension Expense (S-10)	**Total Adjustments (Base Rates)** 0
1	Book Revenues	$23	$3,177	$0	$0	$0	$0	$0	$0	$0	$0	$3,200
2	Book Expenses Other than Depreciation	0	68	(49)	(186)	(234)	0	(32)	0	0	0	($433)
3	State Tax Depreciation	0	0	0	0	(11)	0	0	0	0	0	($11)
4	Interest	0	1	(1)	(0)	(11)	0	(0)	(1)	(9)	(25)	($46)
5	Schedule M Differences		0	0	0	0	0	0	0	0	0	$0
6	State Taxable Income	$23	$3,108	$50	$186	$256	$0	$32	$1	$9	$25	$3,690
7	**State Income Tax**	**$1**	**$196**	**$3**	**$12**	**$16**	**$0**	**$2**	**$0**	**$1**	**$2**	**$233**
8	State Tax Credits	0	0	0	0	0	0	0	0	0	0	$0
9	Net State Income Tax	$1	$196	$3	$12	$16	$0	$2	$0	$1	$2	$233
10	Additional Tax Depreciation	0	0	0	0	0	0	0	0	0	0	$0
11	Other Schedule M Differences	0	0	0	0	0	0	0	0	0	0	$0
12	**Federal Taxable Income**	**$22**	**$2,912**	**$47**	**$174**	**$240**	**$0**	**$30**	**$1**	**$8**	**$23**	**$3,457**
13	Federal Tax @ 35%	8	1,019	16	61	84	0	11	0	3	8	$1,210
14	Federal Tax Credits	0	0	0	0	0	0	0	0	0	0	$0
15	**Current Federal Tax**	**$8**	**$1,019**	**$16**	**$61**	**$84**	**$0**	**$11**	**$0**	**$3**	**$8**	**$1,210**
16	**ITC Adjustment**											$0
17	Deferral	0	0	0	0	0	0	0	0	0	0	$0
18	Restoration	0	0	0	0	0	0	0	0	0	0	$0
19	**Total ITC Adjustment**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**$0**
												$0
20	**Provision for Deferred Taxes**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**$0**
												$0
21	**Total Income Tax**	**$9**	**$1,215**	**$19**	**$73**	**$100**	**$0**	**$13**	**$0**	**$4**	**$10**	**$1,443**

CASE: UE 167
WITNESS: Maury Galbraith

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 200

Direct Testimony

March 15, 2005

Q. PLEASE STATE YOUR NAME AND POSITION.

A. My name is Maury Galbraith. The Public Utility Commission of Oregon (OPUC) employs me as a Senior Economist. My qualifications are shown on Exhibit Staff/201.

Introduction and Summary

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I review Idaho Power Company's (Idaho Power's) proposed net variable power costs (NVPC) in this case.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I begin by summarizing Idaho Power's load-resource balance, or net position, over the spectrum of likely streamflow conditions. I then compare Idaho Power's projected daily competitive market electricity prices to actual market electricity prices seen during the last three years. Next, I discuss the AURORA Electric Market Model (AURORA) used by the company to estimate competitive market-clearing electricity prices and total system NVPC. Finally, I propose an adjustment to Idaho Power's filed NVPC that values Idaho Power's projected wholesale sales and wholesale purchases using actual forward market electricity prices instead of modeled market-clearing prices.

Q. PLEASE SUMMARIZE IDAHO POWER'S FILED NVPC.

A. Idaho Power Exhibit 13 shows projected total system NVPC for 76 separate water conditions (i.e., water years 1928 through 2003). The highest projected NVPC, associated with the lowest hydro condition (water year 1992), is $147.8 million. The lowest projected NVPC is -$7.1 million. The lowest NVPC is associated with the second highest hydro condition (water year 1984). NVPC can be negative when surplus sales revenues exceed fuel and purchased power expenses. A histogram of Idaho Power's projected annual NVPC shows an asymmetric distribution that is skewed towards high NVPC. (Staff Exhibit/202, Galbraith/1.) The company proposes to include the average NVPC of $47.7 million in revenue requirements.

Q. PLEASE SUMMARIZE STAFF'S FINDINGS AND RECOMMENDATIONS.

A. Staff makes the following findings and recommendations:

- Staff finds that Idaho Power's Exhibit 13 shows realistic projections of system dispatch. However, staff recommends that the Commission require Idaho Power to provide hourly results of projected system operations in its next rate filing.
- Staff finds that Idaho Power's Exhibit 13 understates regional market electricity prices. Staff concludes that Idaho Power's AURORA modeling fails to accurately normalize NVPC for the period that rates will likely be in effect.
- Staff recommends that the Commission adjust Idaho Power's normalized purchased power expense and surplus sales revenue using the company's April 30, 2004 electricity forward price curves. This adjustment results in an overall decrease in NVPC of $63.0 million, on a total system basis, and $3.1 million on an Oregon allocated basis.

Idaho Power's Net Position

Q. PLEASE SUMMARIZE IDAHO POWER'S NORMALIZED TEST PERIOD NET POSITION (OR LOAD-RESOURCE BALANCE).

A. On an annual basis, under average hydro conditions, the company projects resources will exceed loads by 321 average megawatts (MWa).[1] Under the lowest hydro condition, the company projects a short position of 107 MWa. Under the highest hydro condition, the company projects a long position of 722 MWa. A histogram of Idaho Power's projected annual net position shows resources exceeding loads by more than 100 MWa in 62 of the 76 projections (82 percent). (Staff Exhibit/202, Galbraith/2.)

Staff Exhibit/202, Galbraith/3 shows the company's monthly net position for each of the 76 water conditions. The chart shows the seasonal pattern of Idaho Power's net position and indicates that to the extent Idaho Power experiences a short position, this typically occurs in June, July, and August.

Q. PLEASE SUMMARIZE IDAHO POWER'S PROJECTIONS OF HYDROELECTRIC GENERATION.

A. Idaho Power's hydroelectric generation primarily consists of Snake River hydro facilities, the largest being Brownlee (585 MW), Oxbow (190 MW) and Hells Canyon (392 MW). On an annual basis, under average hydro conditions, the company projects hydroelectric generation of 1,009 MWa. Hydroelectric generation ranges from a projected low of 557 MWa to a projected high of 1,446 MWa. Staff Exhibit/202, Galbraith/4 shows Idaho Power's hydroelectric generation for each of the 76 water conditions in rank order from highest to lowest output. A histogram of Idaho Power's simulated hydroelectric generation shows a symmetric distribution. (Staff Exhibit/202, Galbraith/5.)

[1] This annual average length is equivalent to 20 percent of the company's annual normalized load used in this case (i.e., 321MWa / 1,610 MWa = 0.199).

Q. PLEASE SUMMARIZE IDAHO POWER'S PROJECTIONS OF COAL-FIRED GENERATION.

A. Idaho Power's coal-fired generation consists of ownerships shares in the Jim Bridger (771 MW), Valmy (284 MW), and Boardman (56 MW) coal plants. On an annual basis, under average hydro conditions, the company projects coal-fired generation of 819 MWa. The minimum projected annual coal generation is 706 MWa. This minimum generation occurs in water year 1974 (a high water condition). The maximum projected annual coal generation is 844 MWa in water year 1930 (a low water condition). A histogram of Idaho Power's projected coal-fired generation indicates the company's coal plants frequently run near capacity. (Staff Exhibit/202, Galbraith/6.)

Q. PLEASE SUMMARIZE IDAHO POWER'S PROJECTIONS OF NATURAL GAS-FIRED GENERATION.

A. Idaho Power has one natural gas-fired resource, the 90 MW Danskin plant. On an annual basis Danskin output is insignificant. The highest annual Danskin output, under any water condition, is less than 0.5 MWa.

Q. ARE IDAHO POWER'S PROJECTIONS OF SYSTEM DISPATCH SENSITIVE TO CHANGES IN MARKET ELECTRICITY PRICES?

A. To a large extent, no. First, monthly hydroelectric generation is shaped to hourly generation based on an hourly load profile, not an hourly market electricity price profile. Second, as I indicated earlier, coal-fired generation is frequently operated at near capacity. Third, Idaho Power's natural gas-fired generation is generally out-of-the-money (i.e., variable operating cost exceeds wholesale market price,) and consequently not operating. As a result, the system dispatch reflected in

Idaho Power Exhibit 13 is not likely to be very responsive to changes in market electricity prices.

Q. DOES STAFF RECOMMEND THAT THE COMMISSION REQUIRE IDAHO POWER TO PROVIDE PROJECTED RESULTS OF SYSTEM OPERATIONS ON AN HOURLY BASIS IN THEIR NEXT RATE FILING?

A. Yes. Idaho Power dispatches its system on a continuous real-time basis. The company makes hourly purchases and sales in order to balance system supply and demand. Hourly NVPC results are a prerequisite for determining whether modeled results reflect actual system operations. In addition, the company should consider shaping monthly discretionary hydro generation to hourly generation based on hourly market electricity prices, not hourly system loads.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS RELATED TO IDAHO POWER'S NET POSITION.

A. On an annual average-hydro basis, Idaho Power is long 321 MWa. Under most hydro conditions, company resources exceed loads by more than 100 MWa. This surplus position allows the company to make wholesale sales to reduce NVPC.

Idaho Power's Projected Market Electricity Prices

Q. DID IDAHO POWER ADDRESS MARKET ELECTRICITY PRICES IN DIRECT TESTIMONY?

A. Yes. Idaho Power witness Greg Said stated that:

> Ignoring the run-up in market prices that occurred in the 2000-2001 time period, the Company has routinely seen market prices in the $40 to $50 per MWh price range during the last two drought years. It has been quite some time since the Company and the region experienced high water conditions, but if high water was to occur, I would expect that market prices would be significantly lower than the $40 to $50 per MWh range, but not as low as the

> $7 to $17 per MWh range expected to accompany high water conditions ten years ago. Idaho Power/Exhibit 12T, Said/5.

Q. DOES STAFF AGREE WITH MR. SAID'S ASSESSMENT OF REGIONAL MARKET ELECTRICITY PRICES DURING LOW WATER CONDITIONS?

A. Yes. The Dow Jones Mid-Columbia (Mid-C) Daily Firm Electricity Price Indexes for 2002-2004 show a high frequency of prices above $40 per MWh. (Staff Exhibit/202, Galbraith/7-8.) Staff Exhibit/202, Galbraith/9-14 show histograms of the Dow Jones Mid-C Price Indexes for 2002-2004. In 2002, 6.9 percent of the on-peak prices and 1.1 percent of the off-peak prices were above $40 per MWh. These percentages jumped dramatically after 2002. In 2003, 46.3 percent of the on-peak prices and 15.9 percent of the off-peak prices were above $40 per MWh. These percentages increased to 74.0 percent on-peak and 42.1 percent off-peak in 2004. The region has routinely seen on-peak prices in the $40 to $50 per MWh range and has recently seen off-peak prices in this range.

Q. ARE THE PRICE PROJECTIONS REFLECTED IN IDAHO POWER EXHIBIT 13 CONSISTENT WITH MR. SAID'S ASSESSMENT OF REGIONAL MARKET ELECTRICITY PRICES DURING LOW WATER CONDITIONS?

A. No. Staff Exhibit/202, Galbraith/15-16 show Idaho Power's projected daily competitive market electricity prices at the Mid-Columbia market hub for on-peak and off-peak hours for five water conditions:

- 1992 (the lowest water condition);
- 1939 (representative of the 25th percentile water condition);
- 1967 (representative of the average water condition);
- 1957 (representative of the 75th percentile water condition); and

- 1983 (the highest water condition).[2]

For comparison purposes I will focus on the price projections for the lowest water conditions. Histograms of Idaho Power's projected Mid-Columbia on-peak and off-peak prices for water condition 1992 show that, during the worst water condition, only 22.9 percent of Idaho Power's projected on-peak prices, and 6.3 percent of the off-peak prices, are above $40 per MWh. (Staff Exhibit/202, Galbraith/17-18). During the 25th percentile water condition, only 2.1 percent of the projected on-peak prices, and 1.0 percent of the off-peak prices, are above $40 per MWh. (Staff Exhibit/202, Galbraith/19-20).

By contrast, as I indicated earlier, 46.3 percent of Dow Jones Mid-C on-peak prices were above $40 per MWh in 2003. In 2004, the percentage jumped to 74.0 percent. The comparison between the Dow Jones Price Indexes and the price projections reflected in Idaho Power Exhibit 13 show that Idaho Power has understated regional electricity prices during low water conditions. Further, Idaho Power's price projections are inconsistent with its own witness's assessment of regional market electricity prices.

Q. DO YOU AGREE WITH MR. SAID'S ASSESSMENT OF LIKELY REGIONAL PRICES DURING HIGH WATER CONDITIONS?

A. Yes. Under high water conditions, all other things constant, I would expect regional electricity prices to frequently be below $40 per MWh. On the other hand, I would not expect to see too many on-peak prices in the $7 to $17 per

[2] Staff calculated daily on-peak and off-peak prices based on Idaho Power's Response to Staff Data Request No. 232. Idaho Power projected market-clearing electricity prices for hours ending 1, 4, 7, 10, 13, 16, 19, and 22 for 96 days per water year (768 hours per year). Staff averaged hours ending 1 and 4 for the daily off-peak price and hours ending 7, 10, 13, 16, 19, and 22 for the daily on-peak price.

MWh range. Market prices in the $7 to $17 per MWh range would typically occur when coal-fired generation is the marginal resource. However, natural gas fuels nearly all of the capacity additions made since 2001 in the western U.S. The supply contribution of natural gas-fired generation has grown to the point where it is unlikely that high water conditions will completely displace natural gas-fired generation as the marginal resource during on-peak hours.

Q. ARE IDAHO POWER'S PROJECTED MARKET ELECTRICITY PRICES CONSISTENT WITH THE COMPANY'S ASSESSMENT OF PRICES DURING HIGH WATER CONDITIONS?

A. No. As Mr. Said indicated, it has been quite some time since the company and the region experienced high water conditions. As a result, we do not have actual market electricity prices during high water conditions to use as a yardstick. We can, however, look at the frequency at which Idaho Power projects prices in the $7 to $17 range during high water conditions. Idaho Power's projected daily Mid-Columbia on-peak prices for the highest water condition average $16.82 per MWh. During the highest water condition, 80 percent of Idaho Power's projected daily Mid-Columbia on-peak prices are below $20 per MWh. (Staff Exhibit/202, Galbraith/25-26.)

The company was unable to provide the projected market electricity prices for each of the 76 hydro conditions. Therefore, the frequency of on-peak prices below $20 per MWh is unavailable for other high water years. However, at the 75th percentile hydro condition, nearly 30 percent of the daily on-peak prices are below $20 per MWh. (Staff Exhibit/202, Galbraith/23-24.)

The high frequency of on-peak prices below $20 per MWh indicates that Idaho Power has understated regional electricity prices during high water conditions. The projected prices do not comport with staff's, or the company's, price expectations at the high end of the hydro generation distribution.

Q. WHAT ARE THE COMPANY'S PROJECTED MID-COLUMBIA PRICES UNDER AVERAGE HYDRO CONDITIONS?

A. Under average hydro conditions, the average daily Mid-Columbia on-peak price is $23.91 per MWh. The highest projected daily on-peak price is $30.83 per MWh. The lowest projected on-peak price is $2.55 per MWh. Nearly 14 percent of the daily on-peak prices, during average water, are below $20 per MWh. (Staff Exhibit/202, Galbraith/21-22). By contrast, during the period January 1, 2004 through June 30, 2004, Idaho Power's forward price curve for calendar year 2005 delivery shows on-peak prices in the $39 per MWh to $51 per MWh range. (Idaho Power Response to Staff Data Request No. 274.)

Q. DOES IDAHO POWER EXHIBIT 13 PROVIDE REALISTIC PROJECTIONS OF IDAHO POWER'S ANNUAL NORMALIZED NVPC?

A. No. As discussed above, the projections in Idaho Power Exhibit 13 significantly understate market electricity prices and, therefore, undervalue Idaho Power's projected wholesale sales and wholesale purchases.

Q. CAN STAFF EXPLAIN THE DISCREPANCY BETWEEN IDAHO POWER'S PRICE PROJECTIONS AND REALISTIC MARKET PRICES FOR THE RATE PERIOD?

A. Yes. As explained below, Idaho Power's flawed price projections are based on its use of the AURORA model.

Idaho Power's Use of the AURORA Electric Market Model

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE AURORA MODEL.

A. AURORA combines economic theory, fundamental economic inputs (e.g., electricity demand, fuel prices, and hydro conditions), the characteristics of regional generating units and transmission links, and dispatch simulation to project hourly market-clearing prices at various trading hubs located within the area of the Western System Coordinating Council. (Idaho Power's Response to Staff Data Request No. 255.)

Q. WHAT IS THE MEANING OF THE PHRASE "HOURLY MARKET-CLEARING PRICE"?

A. An hourly market-clearing price is the price where quantity supplied equals quantity demanded for that hour. Economic theory tells us that perfectly competitive markets clear at a quantity where price equals marginal cost. The AURORA modeling methodology explicitly assumes perfect competition. AURORA sets the hourly electricity prices equal to the variable cost of the last generating units needed to meet demand.

Q. DID IDAHO POWER DEVELOP THE FUNDAMENTAL INPUTS USED IN THE AURORA MODEL?

A. Idaho Power did not specifically address the AURORA model in its direct testimony. It is unclear how many of the model inputs were developed by Idaho Power and how many were developed by EPIS, Inc. (i.e., the supplier of the AURORA model.) It is clear that Idaho Power developed the natural gas price inputs (Idaho Power Response to Staff Data Request No. 66) and the annual and monthly hydroelectric generation inputs for each of the 76 streamflow conditions (Idaho Power Response to Staff Data Request No. 70.)

Q. PLEASE ELABORATE ON THE DEVELOPMENT OF THE NATURAL GAS PRICE INPUTS.

A. Idaho Power developed annual natural gas price inputs for each of the 76 streamflow conditions. Annual prices were estimated for the Henry Hub in Louisiana and were adjusted to incorporate the basis differential between Henry Hub and Idaho Power's system. (Idaho Power Response to Staff Data Request No. 25). The average annual natural gas price at Henry Hub for the 76 hydro conditions is $3.88 per MMBTU (in 2003 dollars). The annual natural gas prices associated with the best hydro conditions range from $2.36 to $3.07 per MMBTU. The natural gas prices associated with the worst hydro conditions range from $4.61 to $5.38 per MMBTU. (Idaho Power Response to Staff Data Request No. 245).

Q. PLEASE COMPARE IDAHO POWER'S ANNUAL HENRY HUB GAS PRICES TO RECENT HENRY HUB SPOT AND FUTURES MARKET PRICES.

A. Idaho Power's annual natural gas price inputs are significantly lower than both recent Henry Hub spot and futures market prices. The Natural Gas Intelligence (NGI) Daily Henry Hub Price Index averaged $3.38 per MMBTU in 2002, $5.47 per MMBTU in 2003, and $5.89 per MMBTU in 2004. Idaho Power's average annual price is $1.59 below the 2003 NGI average and $2.01 below the 2004 NGI average. The NYMEX Futures Contracts for natural gas at Henry Hub, for the 2005 delivery strip, were routinely priced above $3.75 per MMBTU during 2002, above $4.70 per MMBTU during 2003, and above $6.25 per MMBTU during 2004.

Q. WHAT DOES IDAHO POWER INTEND TO ACHIEVE BY INPUTTING AN ANNUAL HENRY HUB NATURAL GAS PRICE FOR EACH OF THE 76 HYDRO CONDITIONS?

A. I believe the intended goal is to normalize NVPC for varying hydro conditions during the period that rates are likely to be in effect. However, it is unclear if Idaho Power developed the natural gas price inputs to: (1) model a relationship between hydro conditions and natural gas prices, (2) model a relationship between hydro conditions and electricity prices, or (3) model a relationship between all three of these variables.

Q. DOES IDAHO POWER'S AURORA MODELING REASONABLY REFLECT THE RELATIONSHIP BETWEEN NORTHWEST HYDRO CONDITIONS AND HENRY HUB (AND PACIFIC NORTHWEST) NATURAL GAS PRICES?

A. No. First, modeling a deterministic relationship between Snake River hydro conditions and Henry Hub natural gas prices is tenuous.[3] Henry Hub spot market prices adjust to national supply and demand trends. I would expect any impact of Northwest hydro conditions on the price of natural gas at Henry Hub to be swamped by other key fundamental drivers, such as gas production rates from mature and frontier gas producing regions, the availability of imported liquefied natural gas, and natural gas storage capacity.

Second, even modeling a deterministic relationship between Northwest hydro conditions and Northwest natural gas prices is tenuous. Recent developments in the natural gas industry have tended to mitigate regional differences in natural gas prices. I would expect Northwest natural gas prices to continue to follow national supply and demand trends.

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[3] A deterministic relationship is one where the effect follows the cause with certainty. For example, a statement, or equation, that indicates that for every 100 MWa change in hydro generation there is a $1 per MWh change in market electricity price, is deterministic. By contrast, a stochastic relationship is one where the relationship between cause and effect is uncertain or probabilistic.

Q. DID STAFF ASK IDAHO POWER TO RE-RUN THE AURORA SIMULATIONS SHOWN IN IDAHO POWER EXHIBIT 13 USING REVISED NATURAL GAS PRICE INPUTS?

A. Yes, in Staff Data Request No. 254. However, once we more fully understood the implications of the modeling, we abandoned that line of inquiry.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS RELATED TO IDAHO POWER'S USE OF THE AURORA MODEL.

A. Deterministic fundamentals-based modeling is not up to the challenge of modeling the complex relationship between Northwest hydro conditions and Northwest energy prices. Idaho Power's AURORA modeling does not reasonably reflect the relationship between Northwest hydro conditions and Northwest natural gas and electricity market prices. As I indicated earlier, the projections in Idaho Power Exhibit 13 significantly understate market electricity prices and, therefore, undervalue Idaho Power's projected wholesale sales and wholesale purchases.

<u>Staff's Proposed Adjustment to Idaho Power's NVPC</u>

Q. WHAT STANDARD SHOULD THE COMMISSION USE TO DETERMINE WHETHER IDAHO POWER HAS APPROPRIATELY NOMALIZED TEST PERIOD NVPC?

A. The appropriate test for NVPC normalization is the 'reasonably certain' standard, rather than the 'known and measurable' standard. All test periods, whether historic or future, are forward-looking representations of the period the new rates are expected to be in effect. The 'reasonably certain' standard tests whether the forward-looking representations can reasonably be expected to occur during the rate period.

Q. ARE THE REGIONAL MARKET-CLEARING ELECTRICITY PRICES REFLECTED IN IDAHO POWER EXHIBIT 13 REASONABLY LIKELY TO OCCUR DURING THE RATE PERIOD?

A. No. The region has routinely seen on-peak prices in the $40 to $50 per MWh range and has recently seen off-peak prices in this range. Analysis of the Dow Jones Mid-Columbia Firm Electricity Price Index shows 46.3 percent of on-peak prices and 15.9 percent of the off-peak prices were above $40 per MWh in 2003. These percentages increased to 74.0 percent on-peak and 42.1 percent off-peak in 2004. In comparison, during the worst water condition, only 22.9 percent of Idaho Power's projected Mid-Columbia on-peak prices, and 6.3 percent of the off-peak prices, are above $40 per MWh. During the 25th percentile water condition, only 2.1 percent of the projected on-peak prices, and 1.0 percent of the off-peak prices, are above $40 per MWh.

Q. HAS STAFF IDENTIFIED MARKET ELECTRICITY PRICES THAT SHOULD BE USED TO CALCULATE IDAHO POWER'S SURPLUS SALES REVENUES AND PURCHASED POWER EXPENSES IN THIS CASE?

A. Yes. The Commission should use Idaho Power's April 30, 2004 forward electricity price curves for the Mid-C hub to adjust Idaho Power's filed NVPC. The average monthly on-peak price for calendar year 2005 is $47.33 per MWh. The average monthly off-peak price for calendar year 2005 is $39.72 per MWh.

Q. WHY SHOULD THE COMMISSION USE IDAHO POWER'S FORWARD PRICE CURVES FROM APRIL 30, 2004?

A. First, using the company's April 30, 2004 price curve is consistent with the period the company used to make adjustments for known ratebase additions in this docket. Second, specific information regarding the 2005 hydro condition was unavailable at this time. Therefore, the forward prices reflected the power market's expectation of average monthly spot market prices during calendar year 2005, under normal hydro conditions. Finally, these forward market prices are more representative of the average level of spot market prices for the period rates from this docket are expected to be in effect, than the modeled market-clearing prices underlying Idaho Power Exhibit 13.

Q. WHAT IS THE AMOUNT OF STAFF'S PROPOSED ADJUSTMENT?

A. On a normalized total company basis, Staff recommends that the Commission increase Idaho Power's purchased power expense by $1.2 million and surplus sales revenue by $64.1 million. The overall adjustment to NVPC is a decrease of $63.0 million ($3.1 million on an Oregon allocated basis). Staff recommends that the Commission set Idaho Power's normalized NVPC at -$15.3 million.

Q. HOW ARE THESE ADJUSTMENTS CALCULATED?

A. Idaho Power's projected monthly energy sales and purchases, under normal hydro conditions, are re-priced using a flat (i.e., 24-hour) electricity price calculated from Idaho Power's on-peak and off-peak forward price curves from April 30, 2004. (Staff Exhibit/202, Galbraith/27.)

Q. IS THE COMMISSION ABLE TO RE-PRICE IDAHO POWER'S PROJECTED SURPLUS SALES AND MARKET PURCHASES ON A MONTHLY ON-PEAK AND OFF-PEAK BASIS?

A. No. Idaho Power was unable to provide the on-peak and off-peak breakdown of projected energy sales. This breakdown was not produced when Idaho Power ran the AURORA simulations. (Idaho Power Response to Staff Data Request No. 244.)

Q. HAS THE COMMISSION USED FORWARD PRICE CURVES TO CALCULATE NORMALIZED NVPC IN PAST PROCEEDINGS?

A. Yes. Rate proceedings where normalized NVPC has been calculated using electricity forward price curves include:

- Docket UE 115: Portland General Electric's (PGE's) proposal to restructure and re-price its services in accordance with the provisions of SB 1149.
- Docket UE 116: PacifiCorp's proposal to restructure and re-price its services in accordance with the provisions of SB 1149.
- Docket UE 139: PGE's application for annual adjustment to Schedule 125 under the terms of the Resource Valuation Mechanism (2003 RVM).
- Docket UE 134: PacifiCorp's application for approval of revised tariffs to reflect new net power costs.
- Docket UE 149: PGE's application for annual adjustment to Schedule 125 under the terms of the Resource Valuation Mechanism (2004 RVM).
- Docket UE 147: PacifiCorp's request for a general rate increase.
- Docket UE 161: PGE's application for annual adjustment to Schedule 125 under the terms of the Resource Valuation Mechanism (2005 RVM).

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 167
WITNESS: Maury Galbraith

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualifications Statement

March 15, 2005

WITNESS QUALIFICATION STATEMENT

NAME:	Maury Galbraith
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist, Energy Division
ADDRESS:	550 Capitol Street NE Suite 215 Salem, Oregon 97301-2551
EDUCATION:	Graduate Student in Environmental Studies Program (1995 – 1997) University of Montana Missoula, Montana Master of Arts in Economics (1992) Washington State University Pullman, Washington Bachelor of Science in Economics (1989) University of Oregon Eugene, Oregon
EXPERIENCE:	The Public Utility Commission of Oregon has employed me since April 2000. My primary responsibility is to provide expert analysis of issues related to power supply in the regulation of electric utility rates. From April 1998 through March 2000 I was a Research Specialist with the State of Washington Office of the Administrator for the Courts in Olympia, Washington. From April 1993 through August 1995 I was a Safety Economist with the Pacific Institute for Research and Evaluation in Bethesda, Maryland.

CASE: UE 167
WITNESS: Maury Galbraith

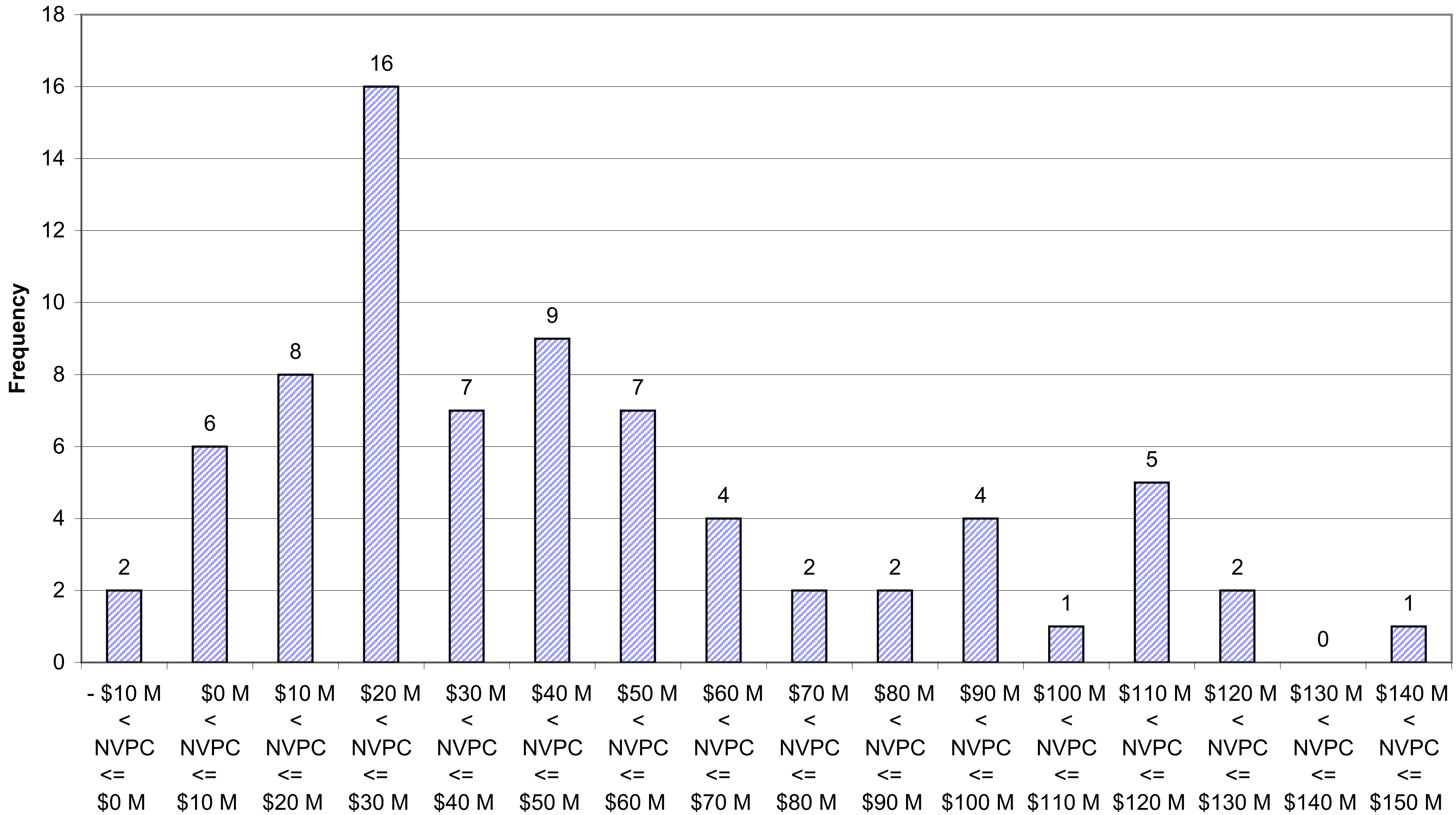
PUBLIC UTILITY COMMISSION OF OREGON

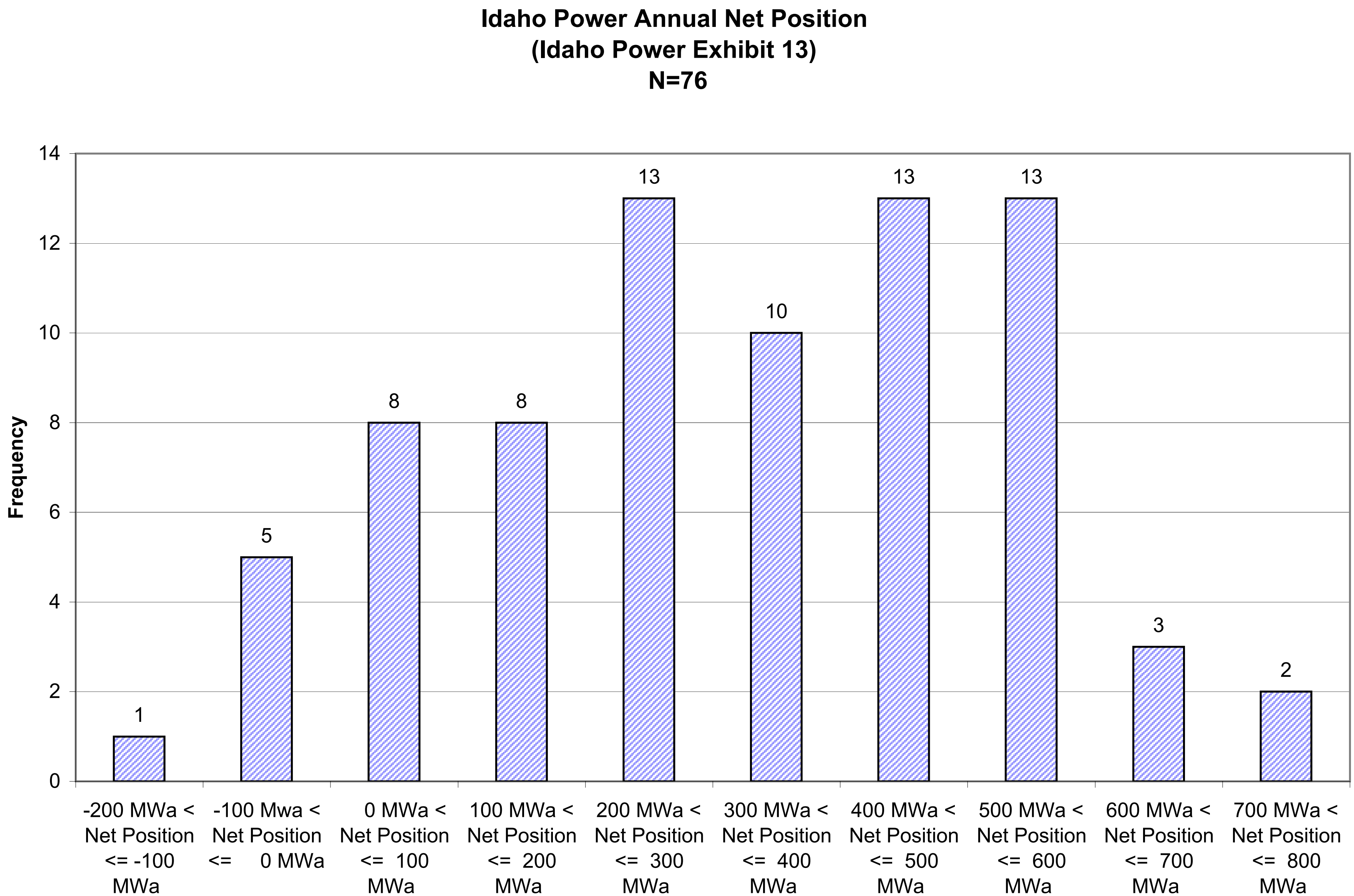
STAFF EXHIBIT 202

Exhibits in Support of Direct Testimony

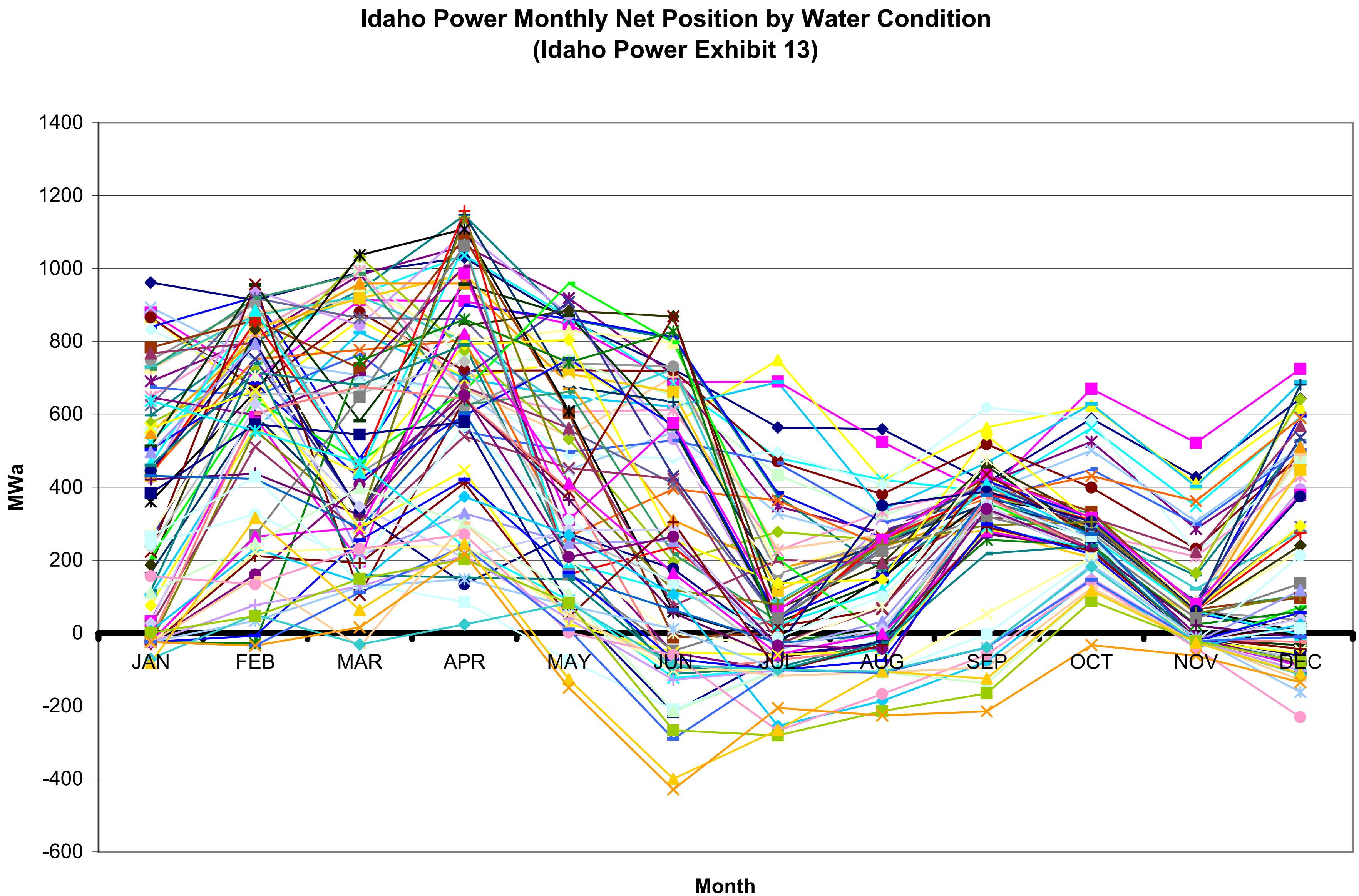
March 15, 2005

Idaho Power Annual NVPC
(Idaho Power Exhibit 13)
N=76

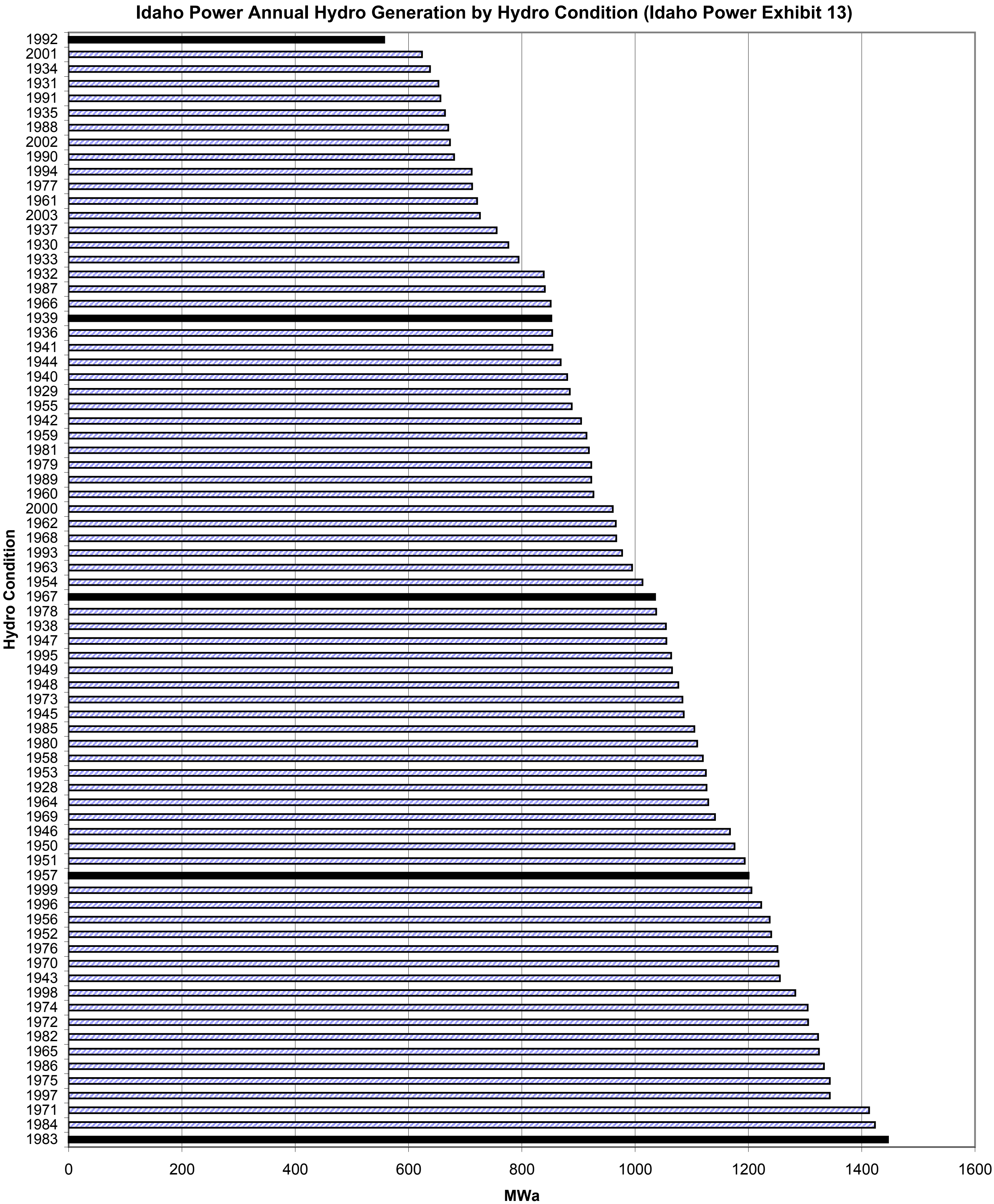


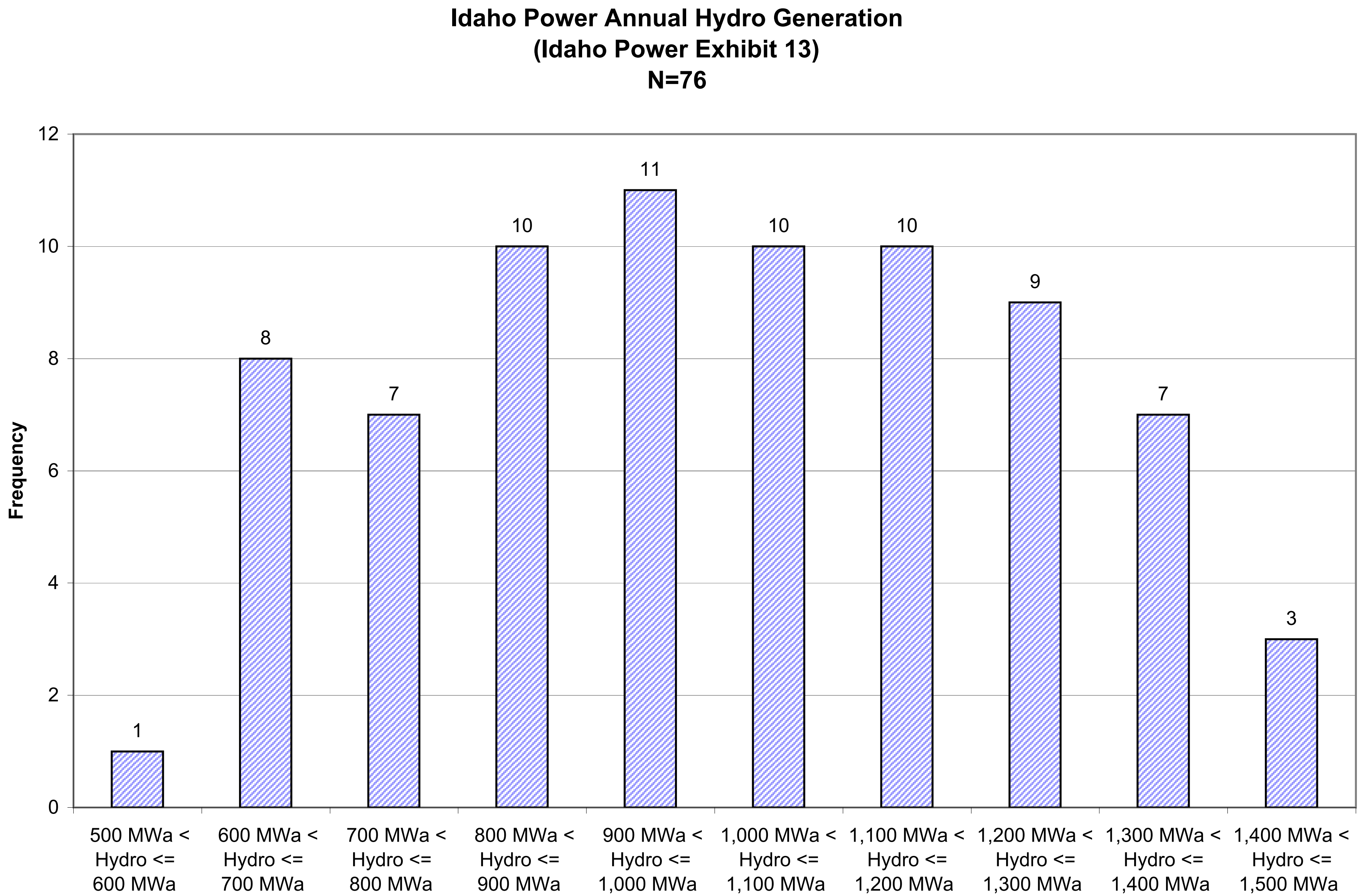


UE 167
STAFF EXHIBIT 202
GALBRAITH/2

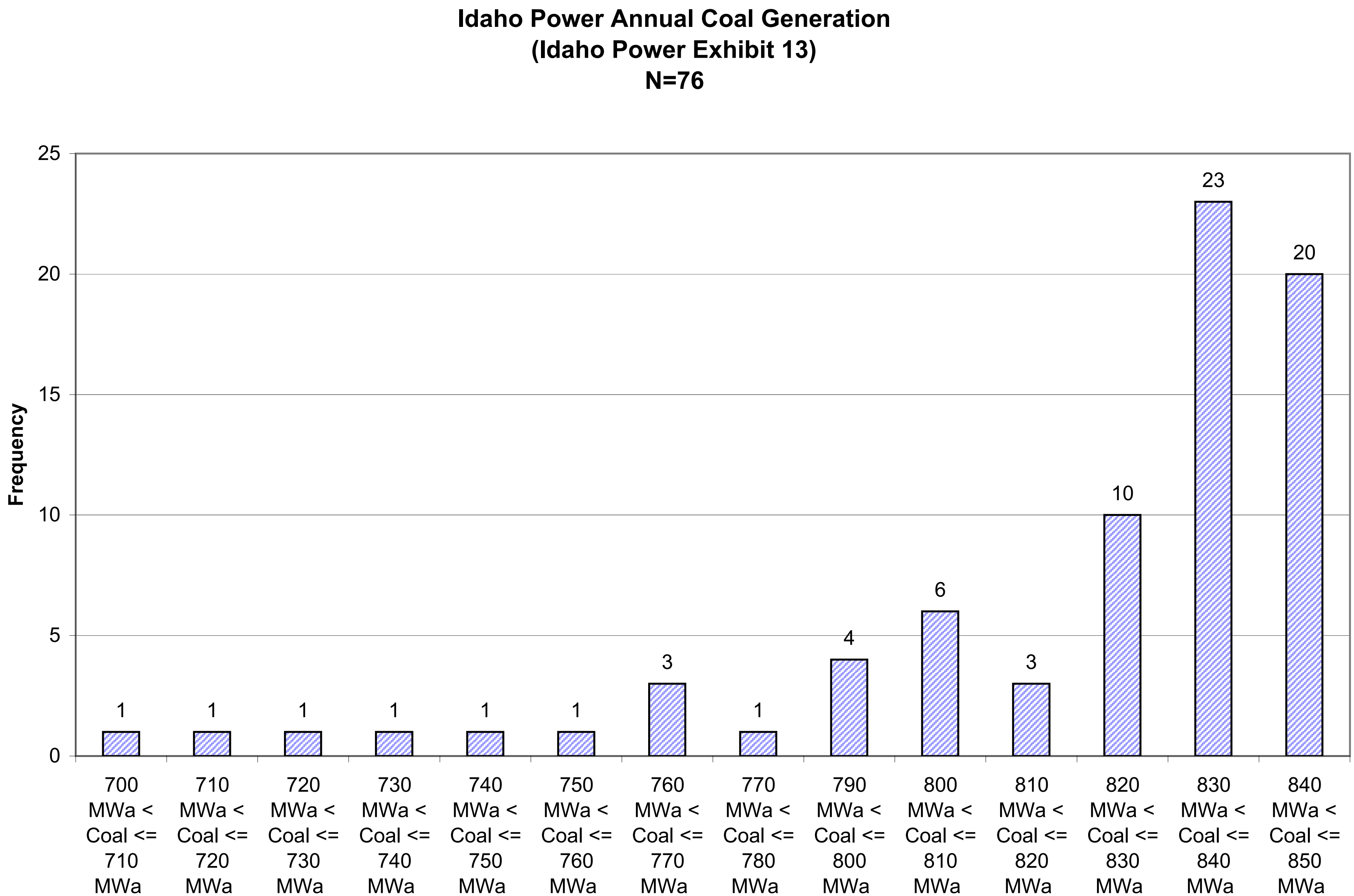


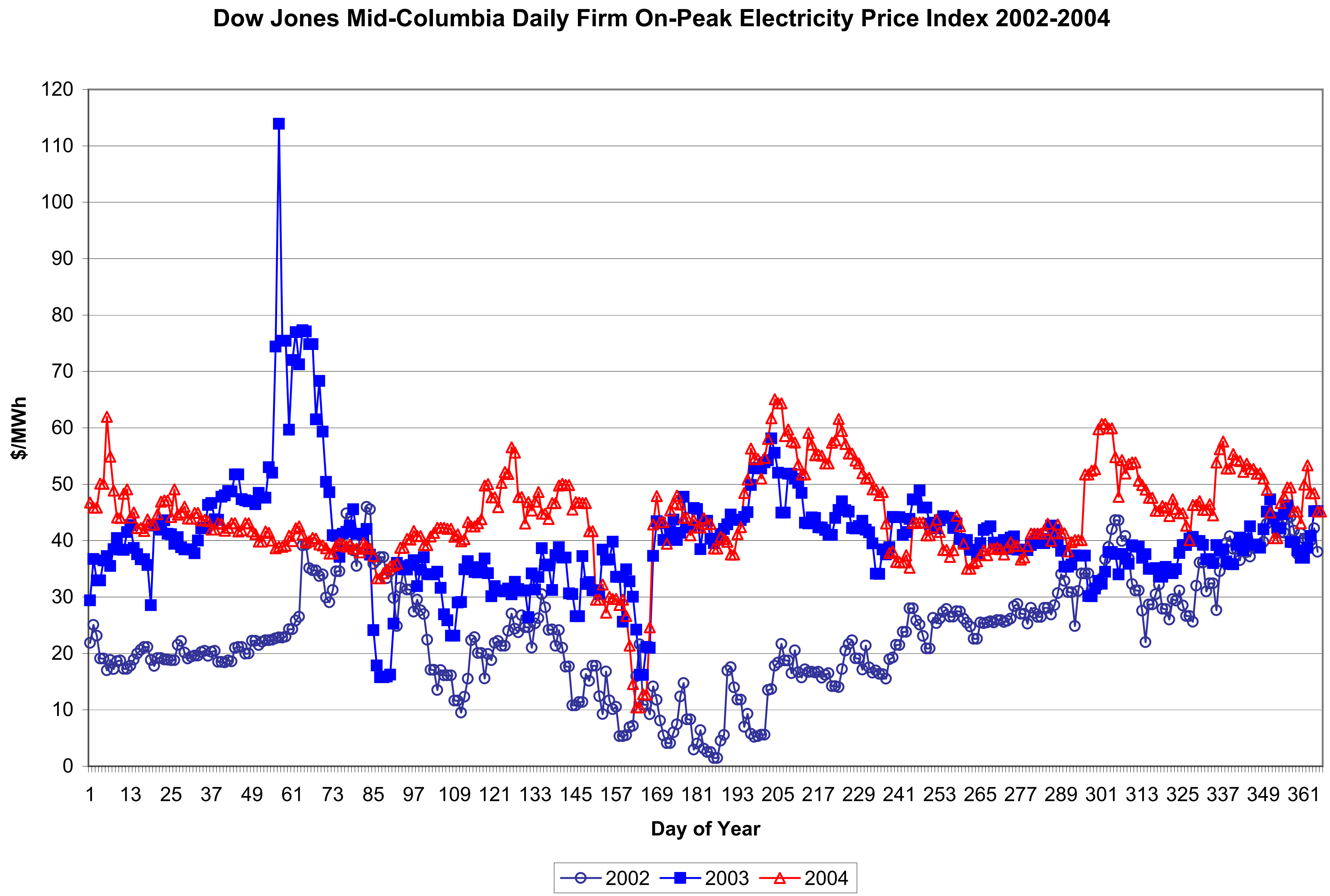
UE 167
STAFF EXHIBIT 202
GALBRAITH/3


Idaho Power Annual Hydro Generation by Hydro Condition (Idaho Power Exhibit 13)
Hydro Condition
1992
2001
1934
1931
1991
1935
1988
2002
1990
1994
1977
1961
2003
1937
1930
1933
1932
1987
1966
1939
1936
1941
1944
1940
1929
1955
1942
1959
1981
1979
1989
1960
2000
1962
1968
1993
1963
1954
1967
1978
1938
1947
1995
1949
1948
1973
1945
1985
1980
1958
1953
1928
1964
1969
1946
1950
1951
1957
1999
1996
1956
1952
1976
1970
1943
1998
1974
1972
1982
1965
1986
1975
1997
1971
1984
1983
0
200
400
600
800
1000
1200
1400
1600
MWa

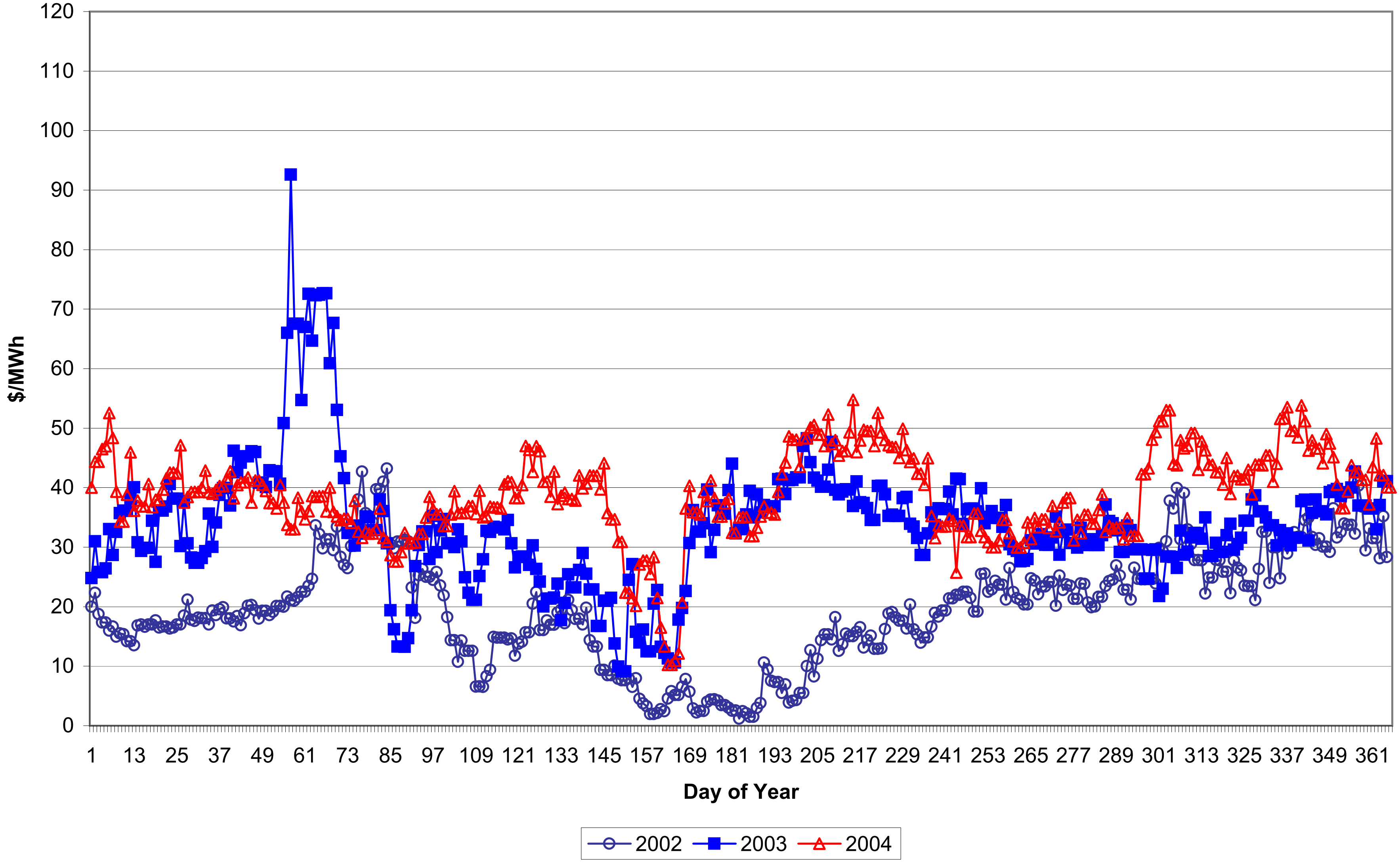


Idaho Power Annual Hydro Generation
(Idaho Power Exhibit 13)
N=76
Frequency
12
10
8
6
4
2
0
1
8
7
10
11
10
10
9
7
3
500 MWa < Hydro <= 600 MWa
600 MWa < Hydro <= 700 MWa
700 MWa < Hydro <= 800 MWa
800 MWa < Hydro <= 900 MWa
900 MWa < Hydro <= 1,000 MWa
1,000 MWa < Hydro <= 1,100 MWa
1,100 MWa < Hydro <= 1,200 MWa
1,200 MWa < Hydro <= 1,300 MWa
1,300 MWa < Hydro <= 1,400 MWa
1,400 MWa < Hydro <= 1,500 MWa


Idaho Power Annual Coal Generation
(Idaho Power Exhibit 13)
N=76
Frequency
25
20
15
10
5
0
1
1
1
1
1
1
3
1
4
6
3
10
23
20
700 MWa < Coal <= 710 MWa
710 MWa < Coal <= 720 MWa
720 MWa < Coal <= 730 MWa
730 MWa < Coal <= 740 MWa
740 MWa < Coal <= 750 MWa
750 MWa < Coal <= 760 MWa
760 MWa < Coal <= 770 MWa
770 MWa < Coal <= 780 MWa
790 MWa < Coal <= 800 MWa
800 MWa < Coal <= 810 MWa
810 MWa < Coal <= 820 MWa
820 MWa < Coal <= 830 MWa
830 MWa < Coal <= 840 MWa
840 MWa < Coal <= 850 MWa


Dow Jones Mid-Columbia Daily Firm On-Peak Electricity Price Index 2002-2004
$/MWh
120
110
100
90
80
70
60
50
40
30
20
10
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
289
301
313
325
337
349
361
Day of Year
2002
2003
2004

Dow Jones Mid-Columbia Daily Firm Off-Peak Electricity Price Index 2002-2004



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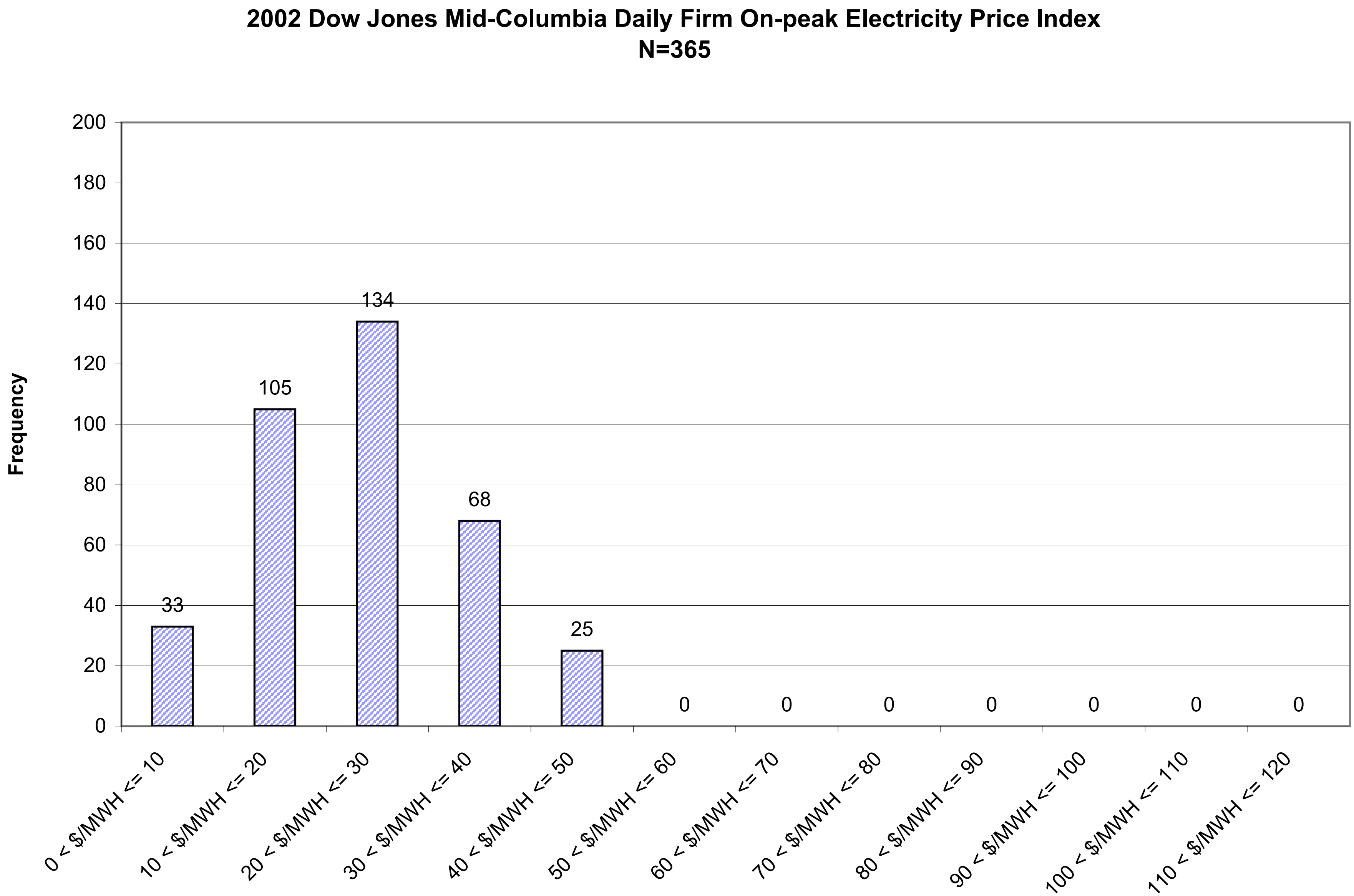
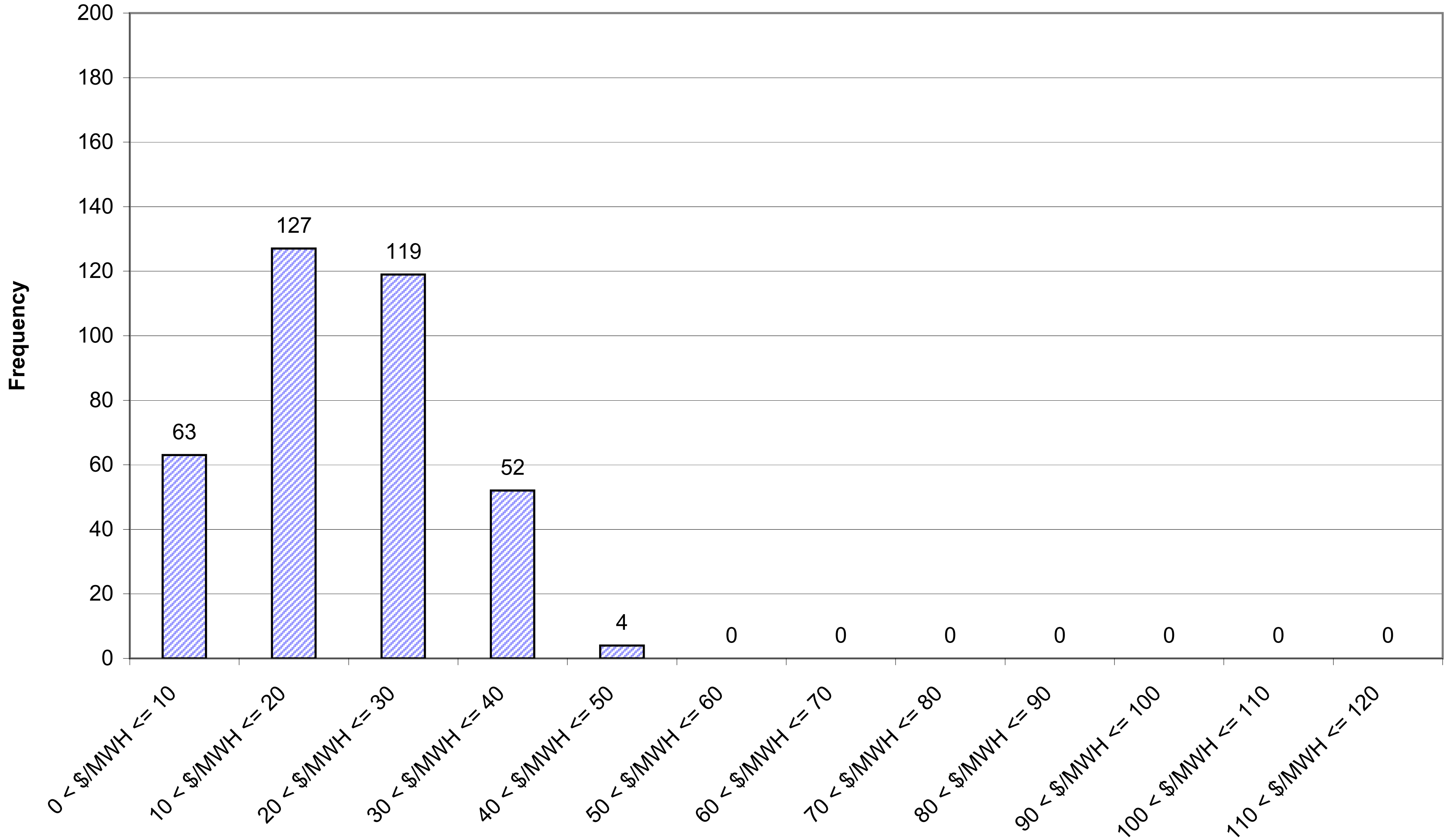
STAFF EXHIBIT 202
GALBRAITH/8

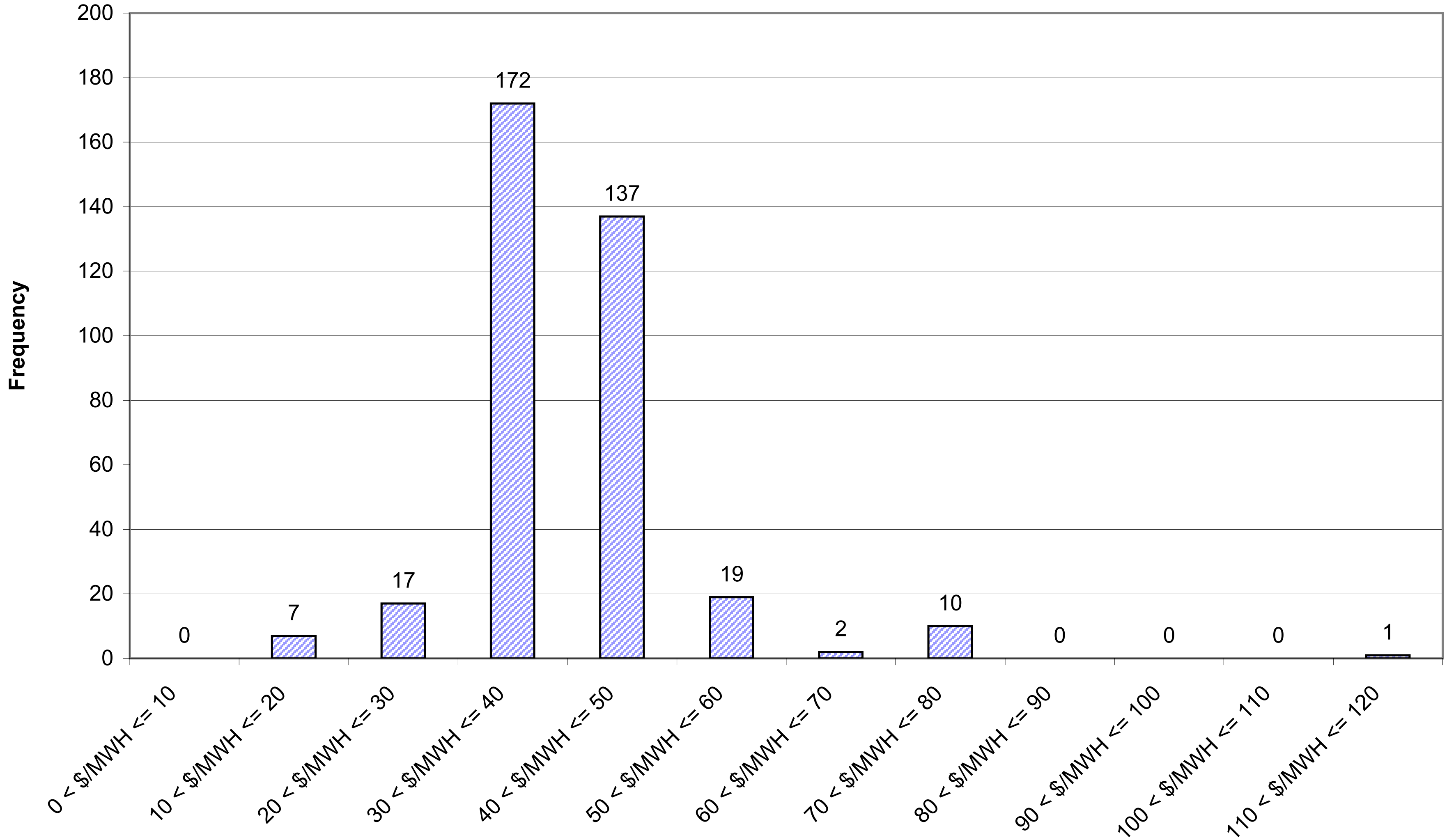


UE 167
STAFF EXHIBIT 202
GALBRAITH/9

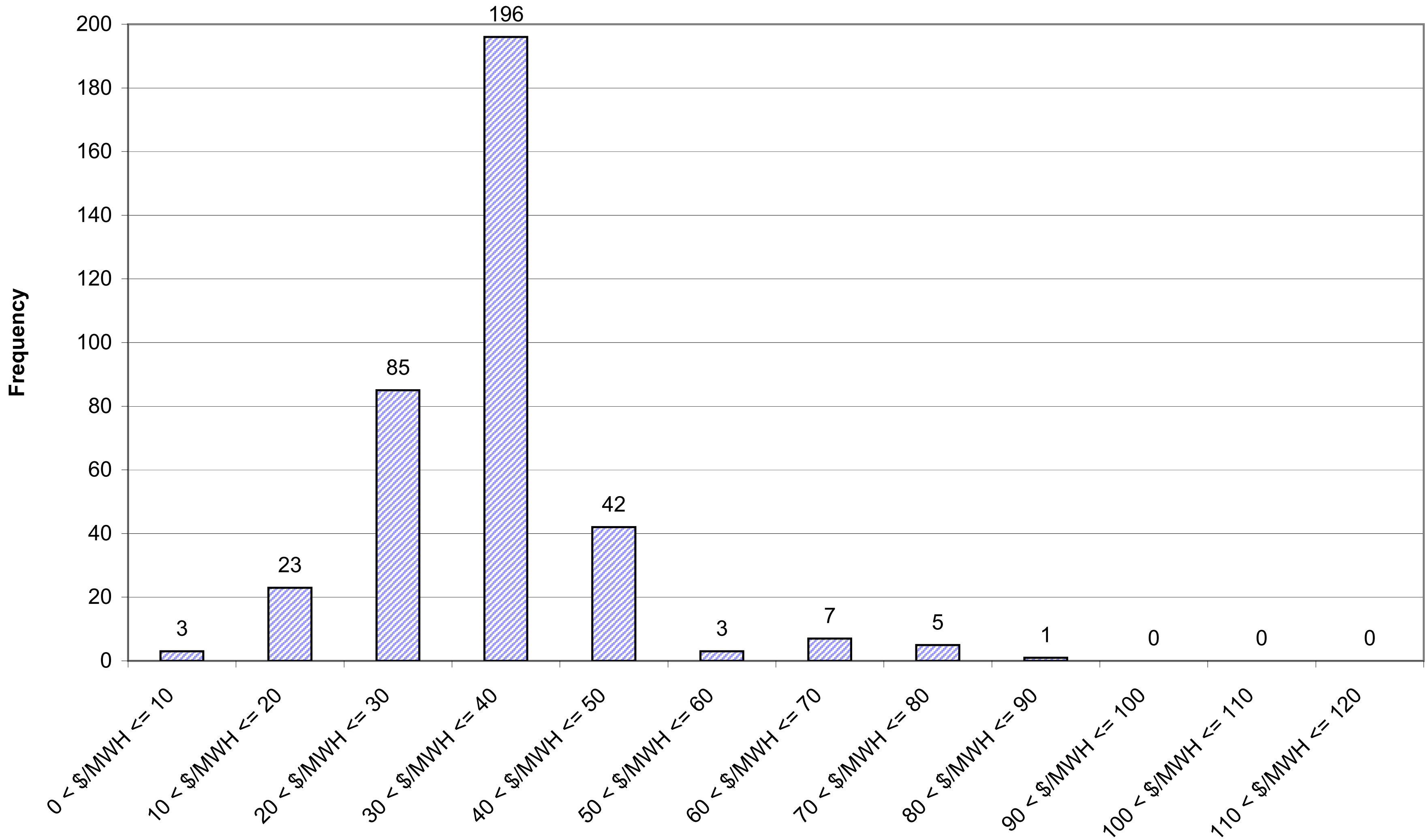
2002 Dow Jones Mid-Columbia Daily Firm Off-Peak Electricity Price Index
N=365



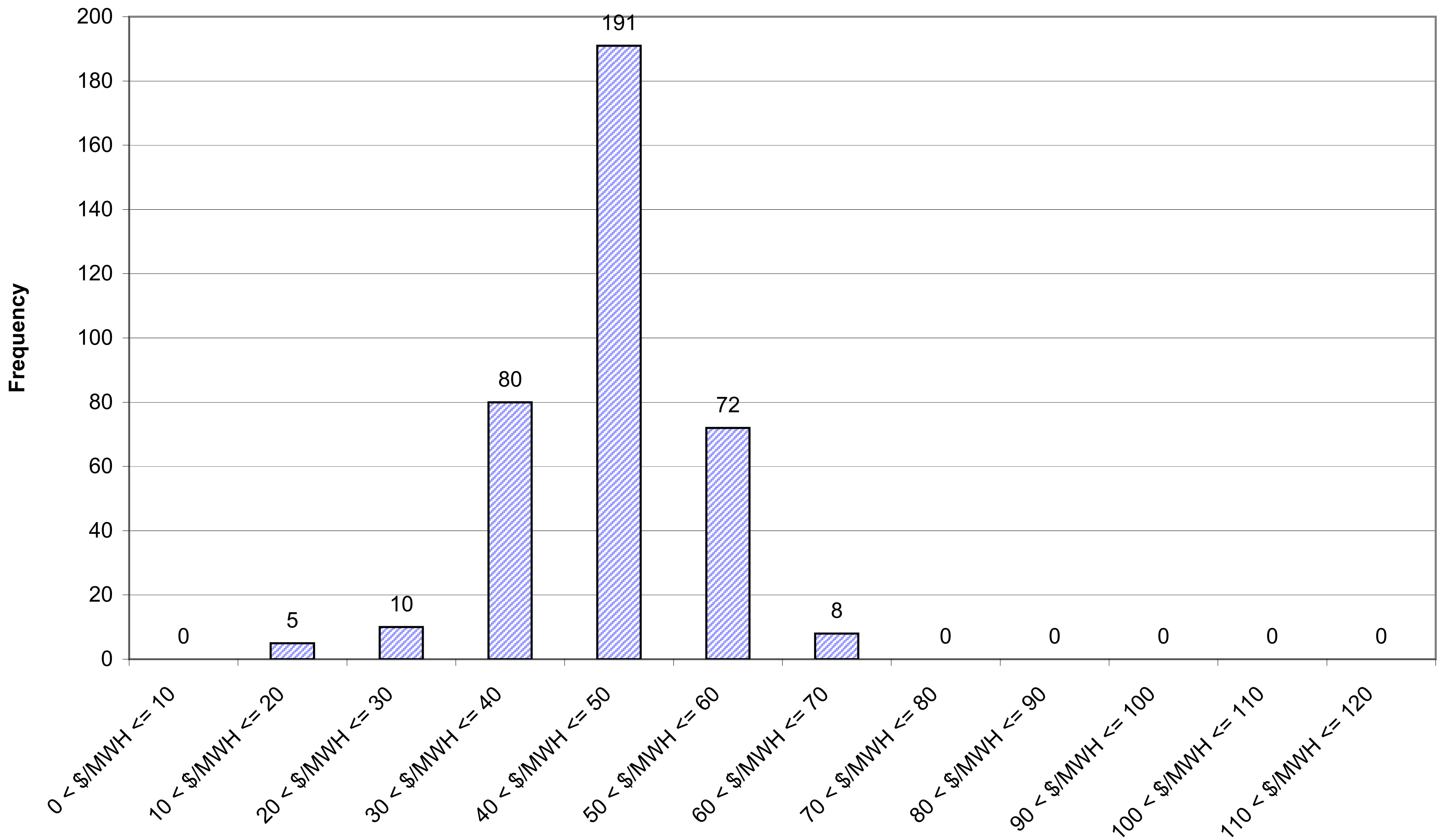
2003 Dow Jones Mid-Columbia Daily Firm On-peak Electricity Price Index
N=365



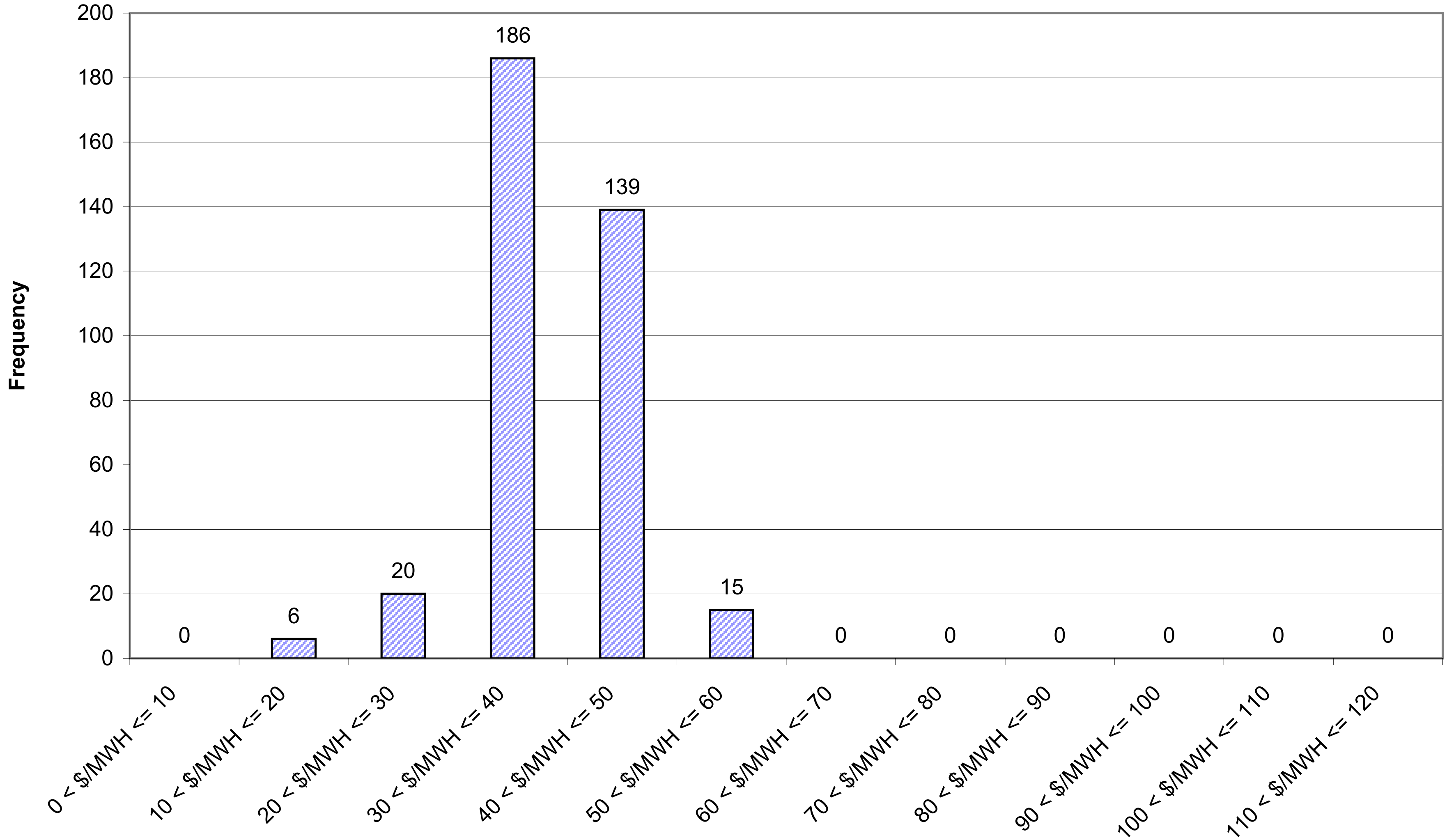
2003 Dow Jones Mid-Columbia Daily Firm Off-Peak Electricity Price Index
N=365

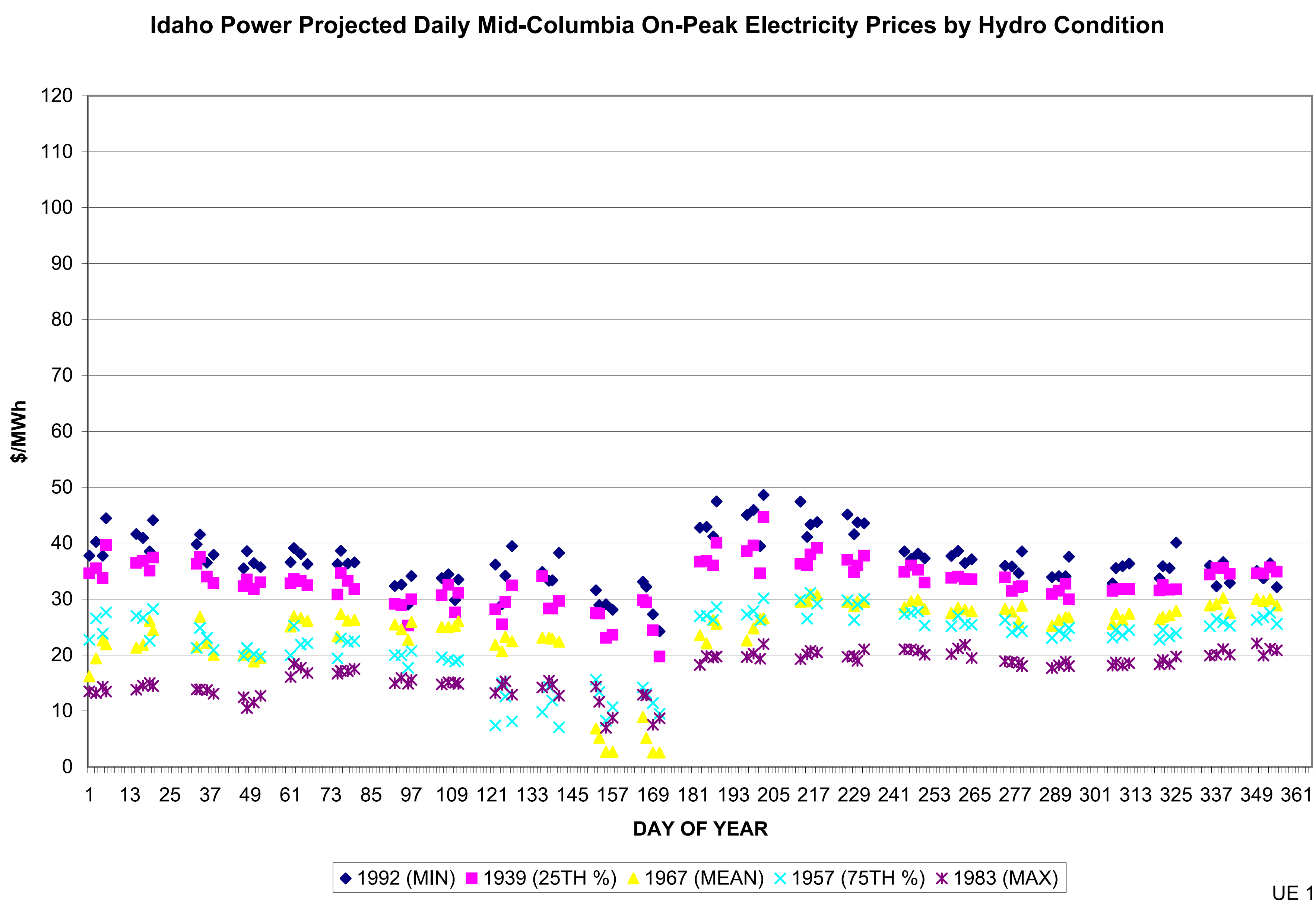


2004 Dow Jones Mid-Columbia Daily Firm On-Peak Electricity Price Index
N=366

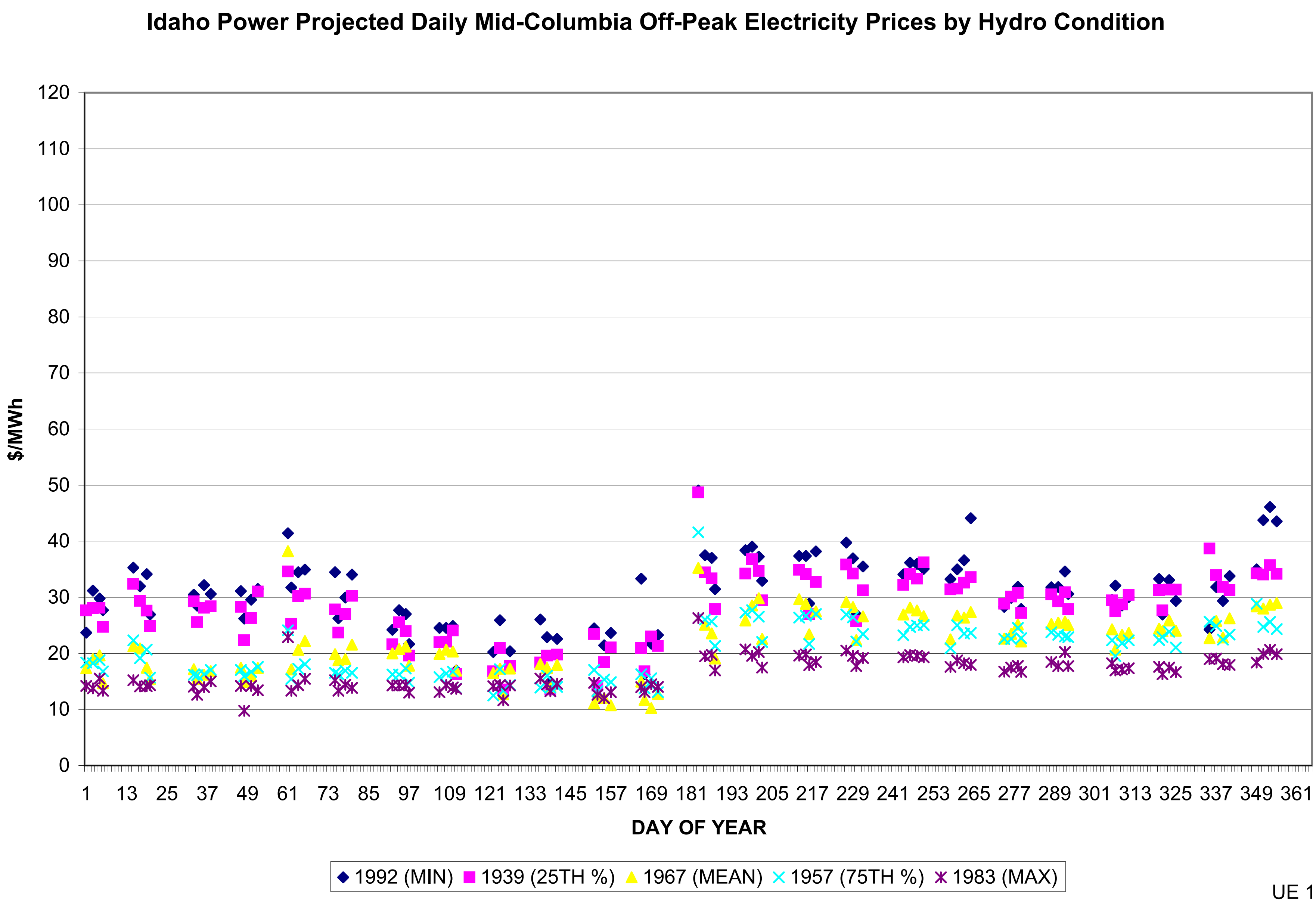


2004 Dow Jones Mid-Columbia Daily Firm Off-Peak Electricity Price Index
N=366



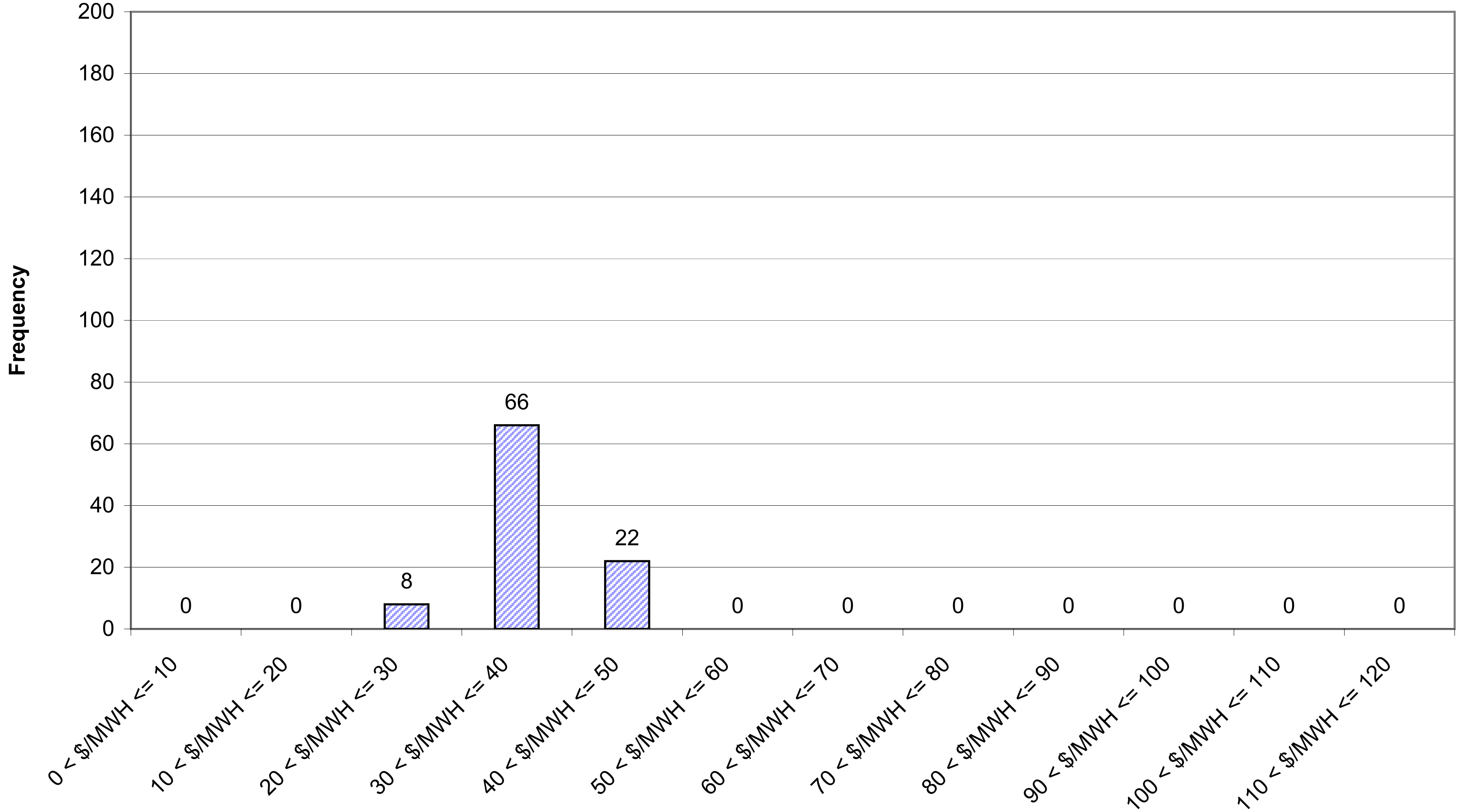


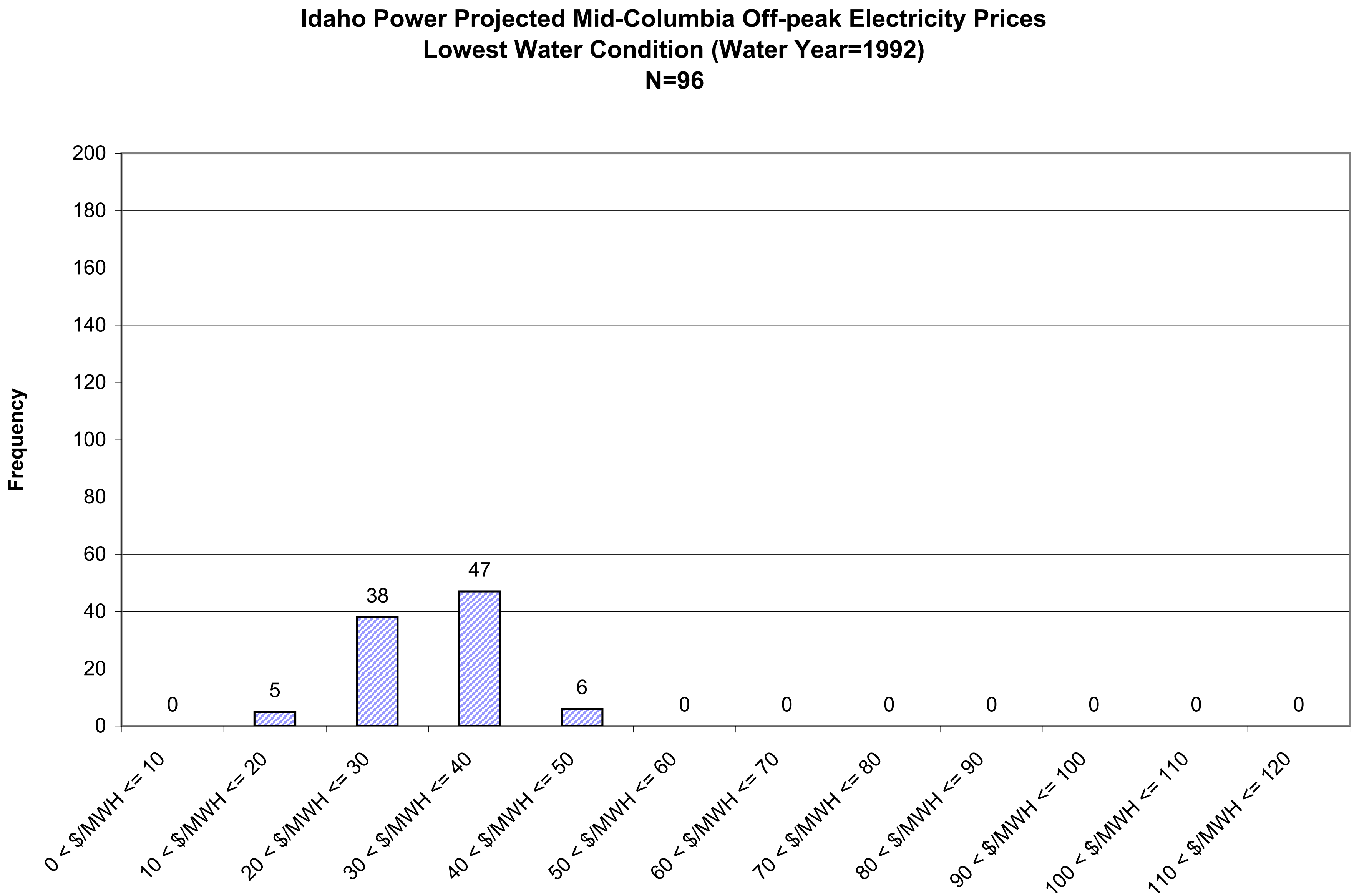
UE 167
STAFF EXHIBIT 202
GALBRAITH/15



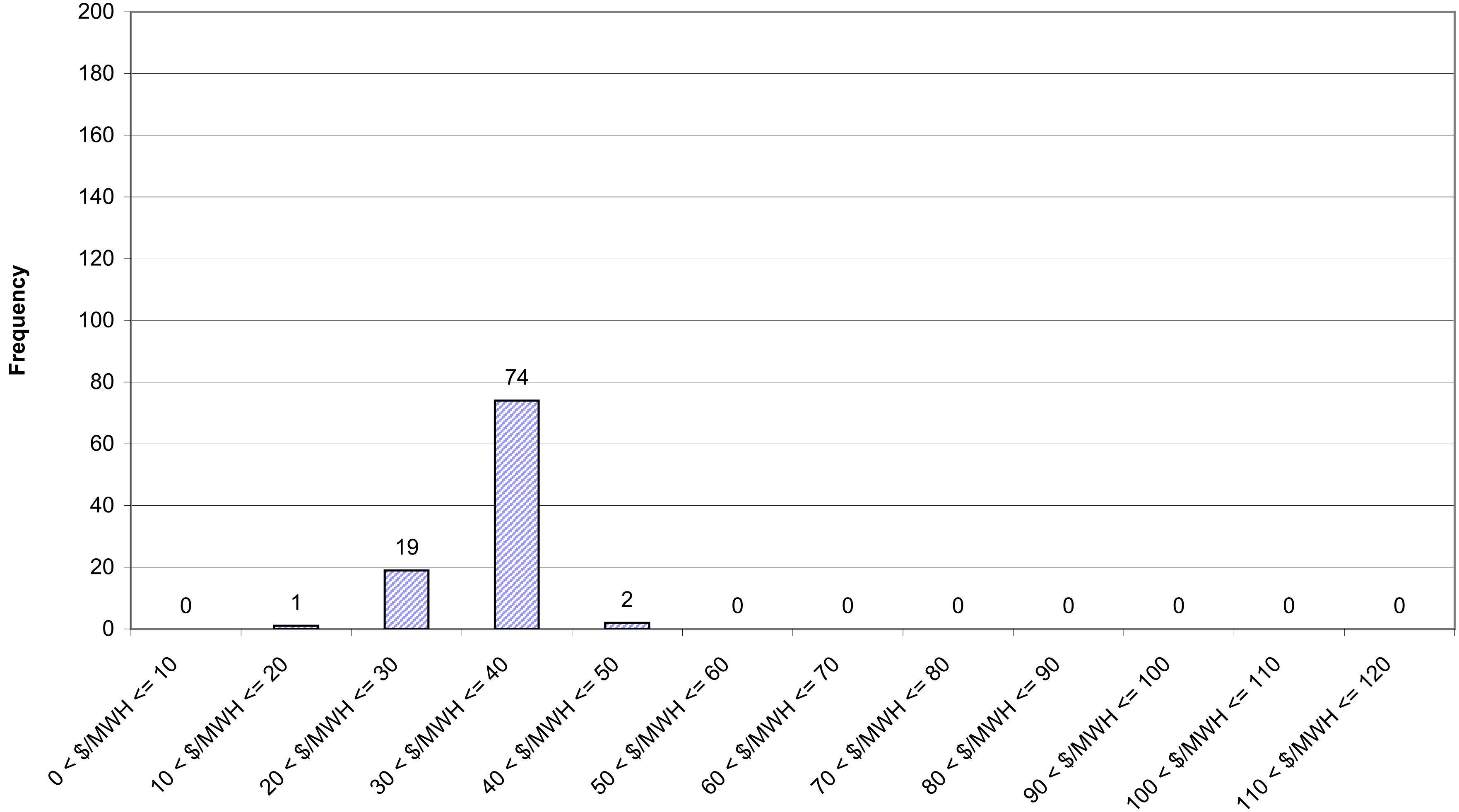
UE 167
STAFF EXHIBIT 202
GALBRAITH/16

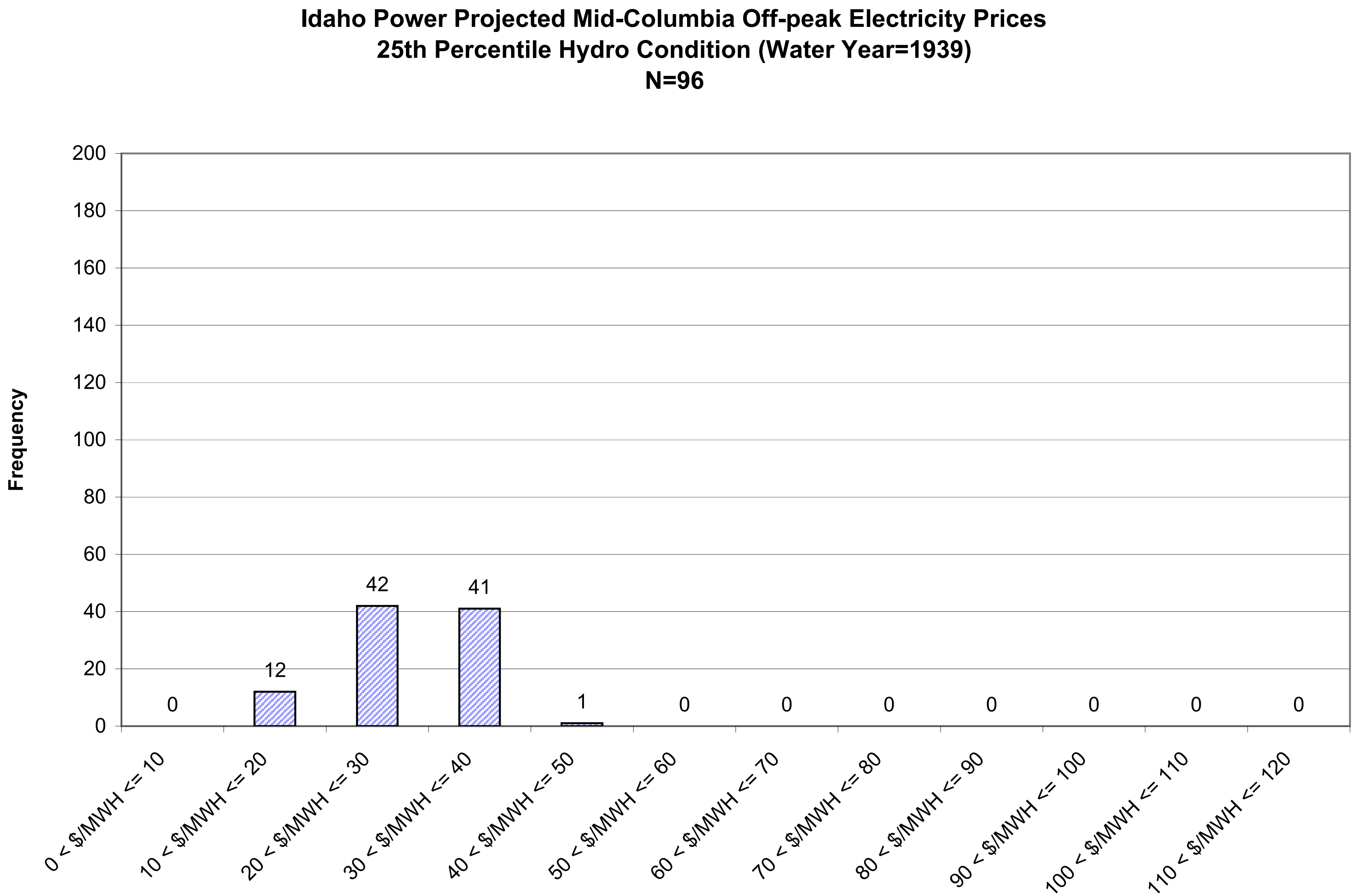
Idaho Power Projected Mid-Columbia On-peak Electricity Prices
Lowest Hydro Condition (Water Year=1992)
N=96



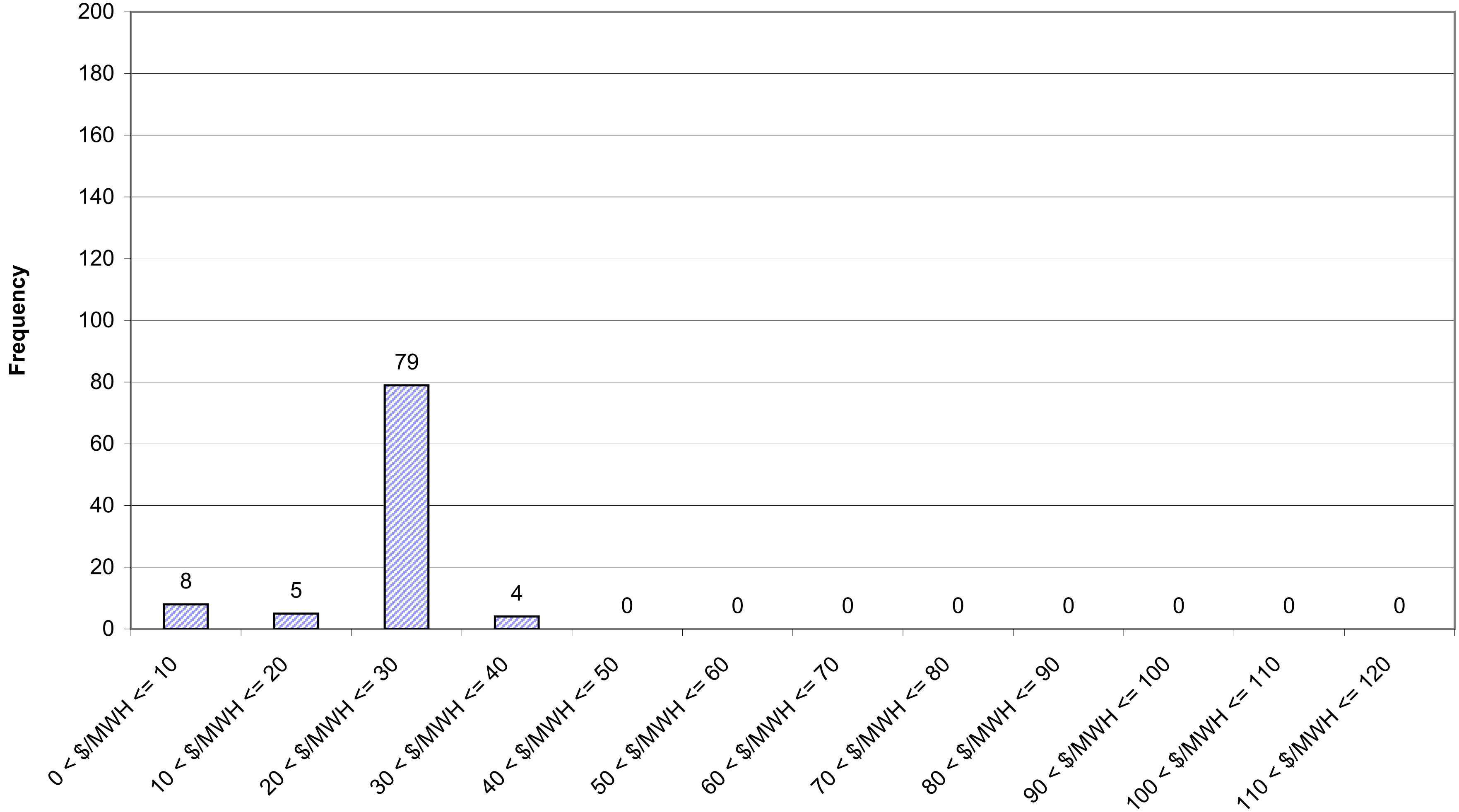

Idaho Power Projected Mid-Columbia Off-peak Electricity Prices
Lowest Water Condition (Water Year=1992)
N=96
Frequency
200
180
160
140
120
100
80
60
40
20
0
0
5
38
47
6
0
0
0
0
0
0
0
0 < $/MWH <= 10
10 < $/MWH <= 20
20 < $/MWH <= 30
30 < $/MWH <= 40
40 < $/MWH <= 50
50 < $/MWH <= 60
60 < $/MWH <= 70
70 < $/MWH <= 80
80 < $/MWH <= 90
90 < $/MWH <= 100
100 < $/MWH <= 110
110 < $/MWH <= 120

Idaho Power Projected Mid-Columbia On-peak Electricity Prices
25th Percentile Hydro Condition (Water Year=1939)
N=96

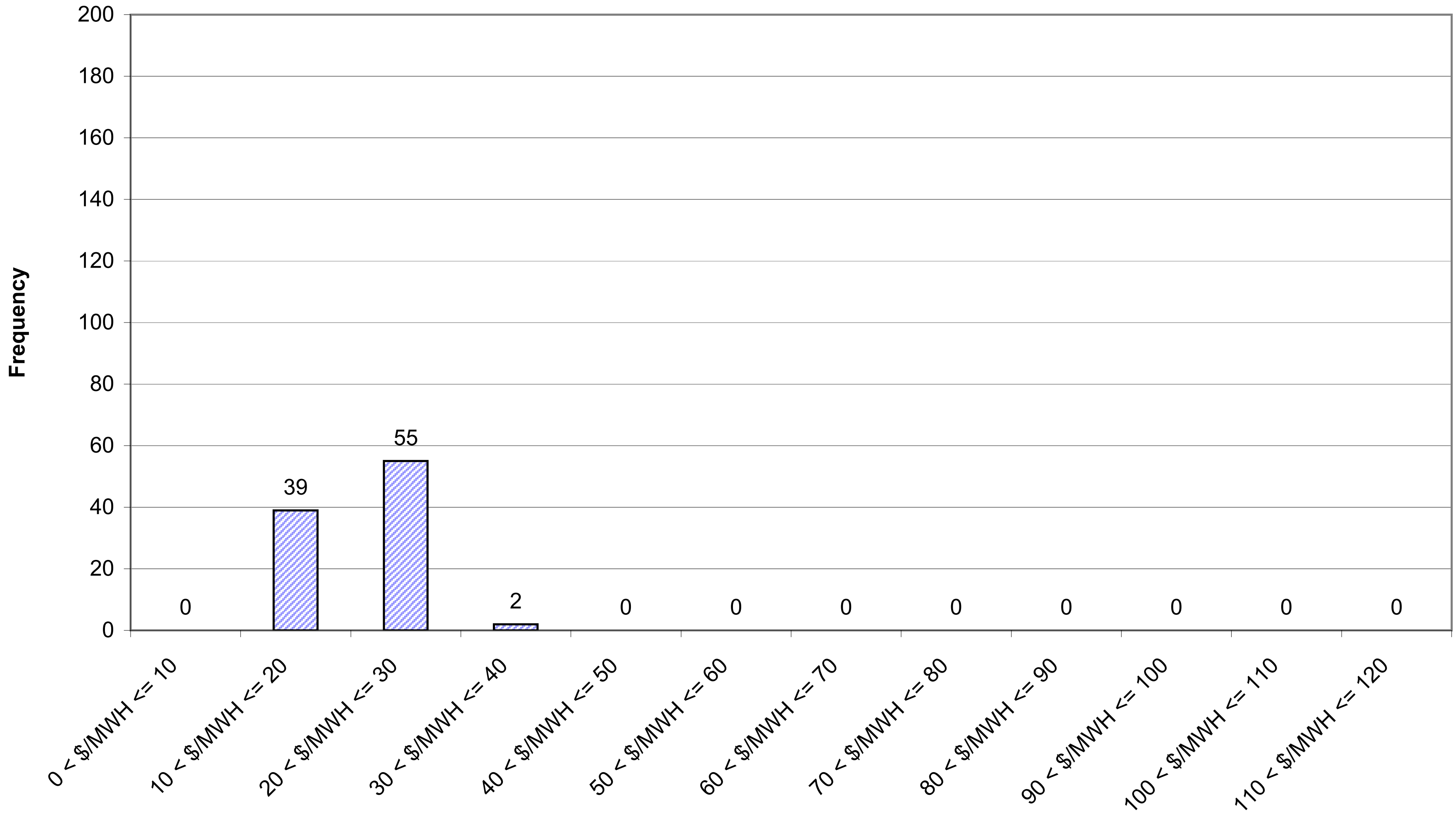



Idaho Power Projected Mid-Columbia Off-peak Electricity Prices
25th Percentile Hydro Condition (Water Year=1939)
N=96
Frequency
200
180
160
140
120
100
80
60
40
20
0
0
12
42
41
1
0
0
0
0
0
0
0
0 < $/MWH <= 10
10 < $/MWH <= 20
20 < $/MWH <= 30
30 < $/MWH <= 40
40 < $/MWH <= 50
50 < $/MWH <= 60
60 < $/MWH <= 70
70 < $/MWH <= 80
80 < $/MWH <= 90
90 < $/MWH <= 100
100 < $/MWH <= 110
110 < $/MWH <= 120

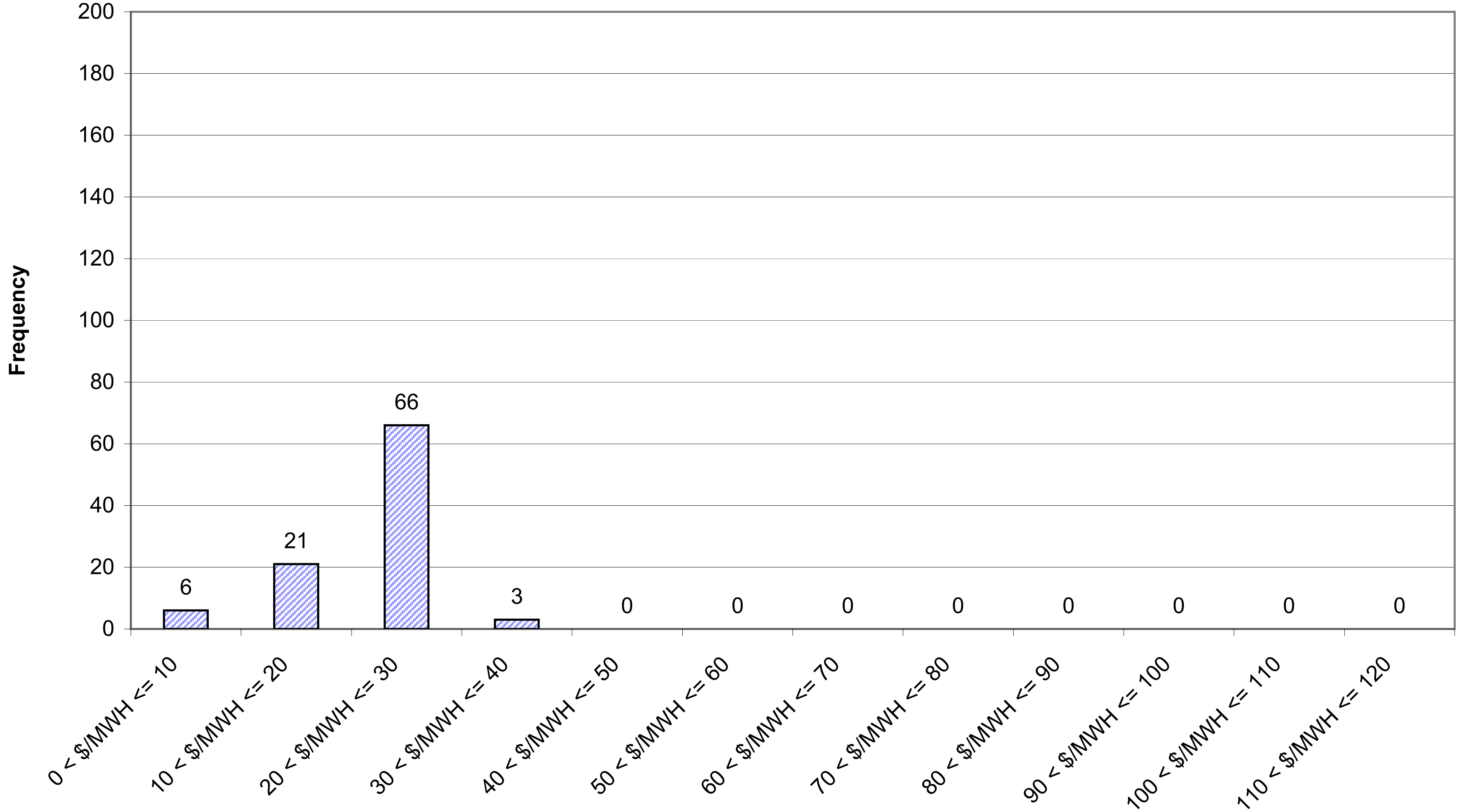
Idaho Power Projected Mid-Columbia On-peak Electricity Prices
Average Hydro Condition (Water Year=1967)
N=96



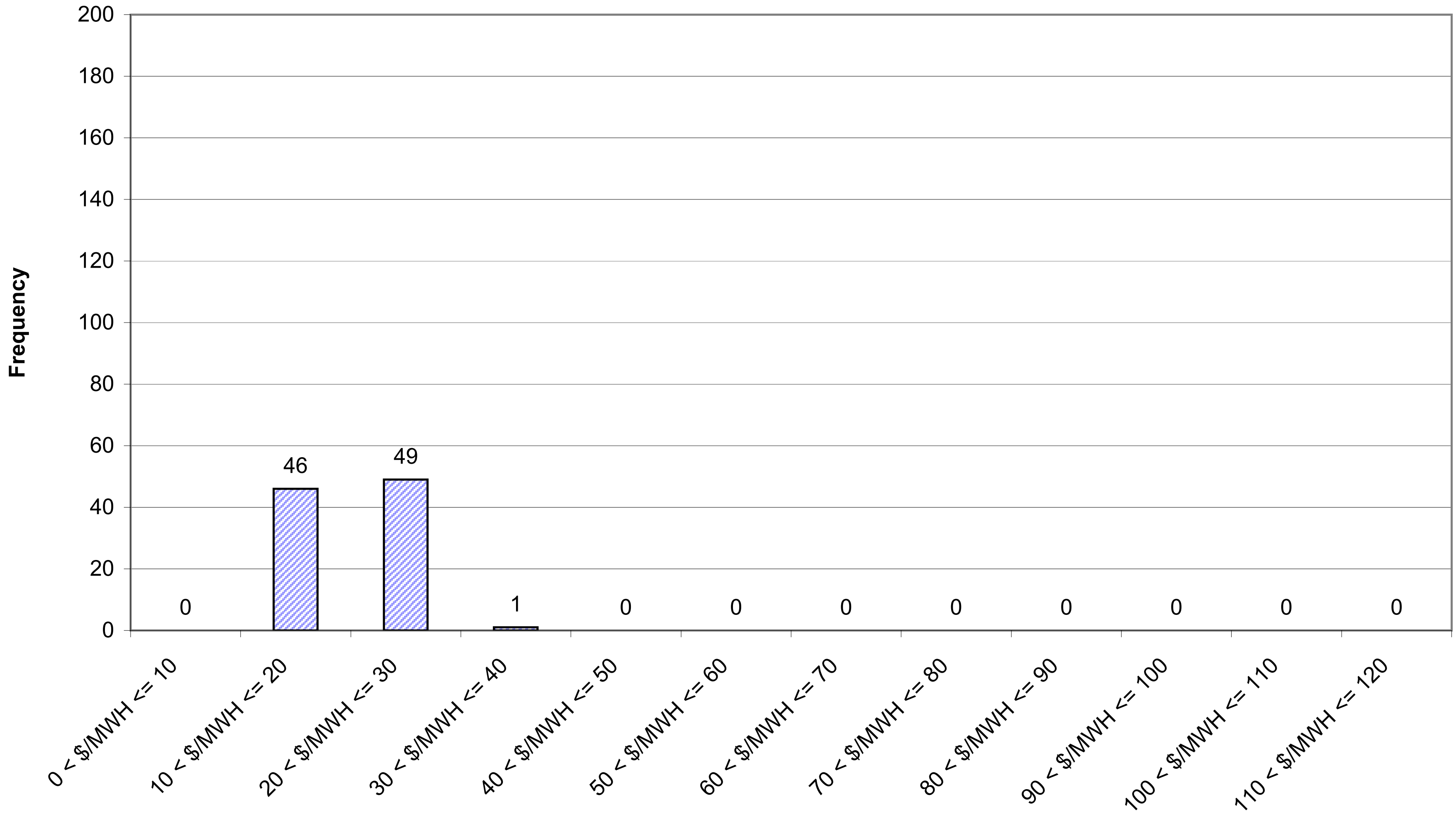
Idaho Power Projected Mid-Columbia Off-peak Electricity Prices
Average Hydro Condition (Water Year=1967)
N=96



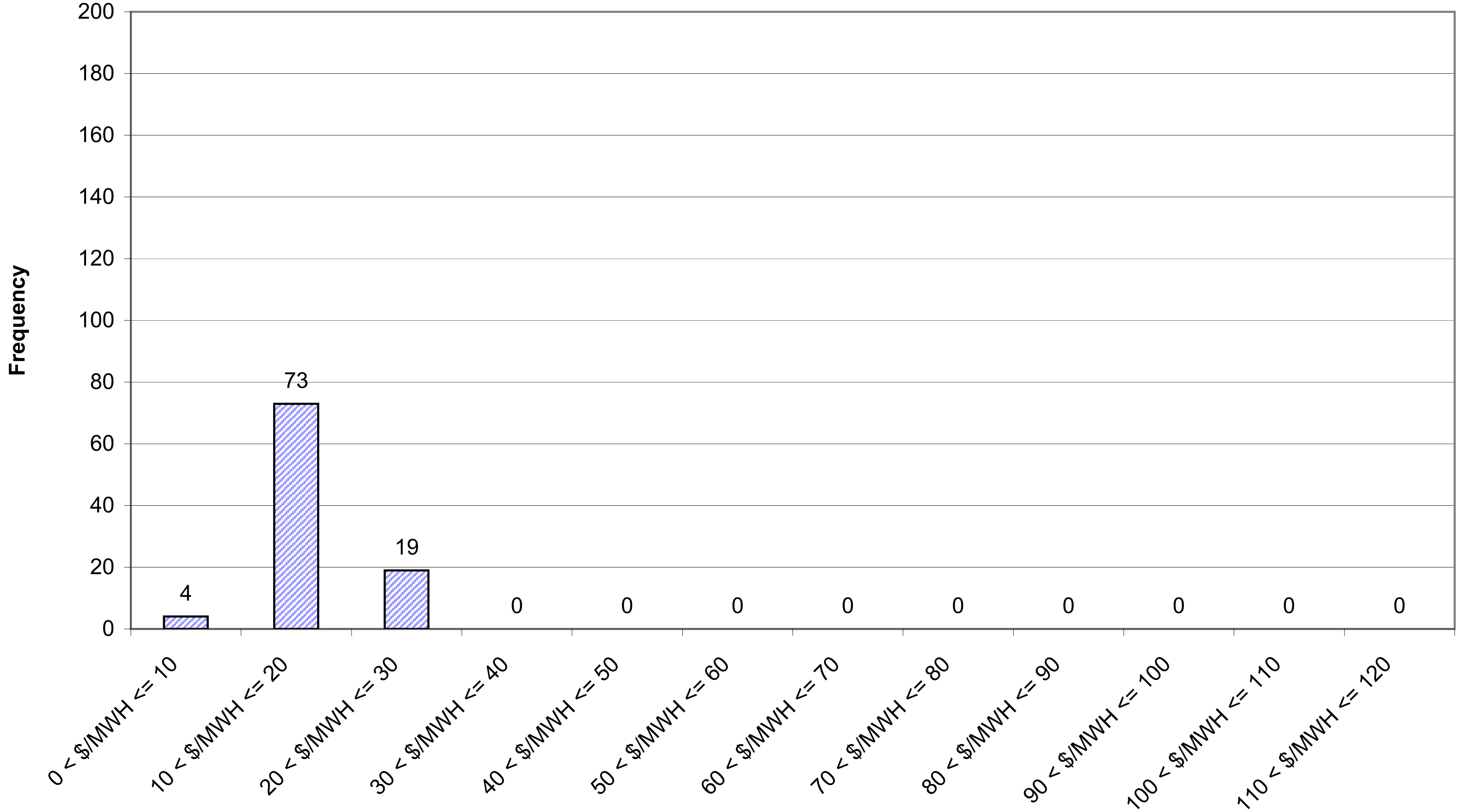
Idaho Power Projected Mid-Columbia On-peak Electricity Prices
75th Percentile Hydro Condition (Water Year=1957)
N=96



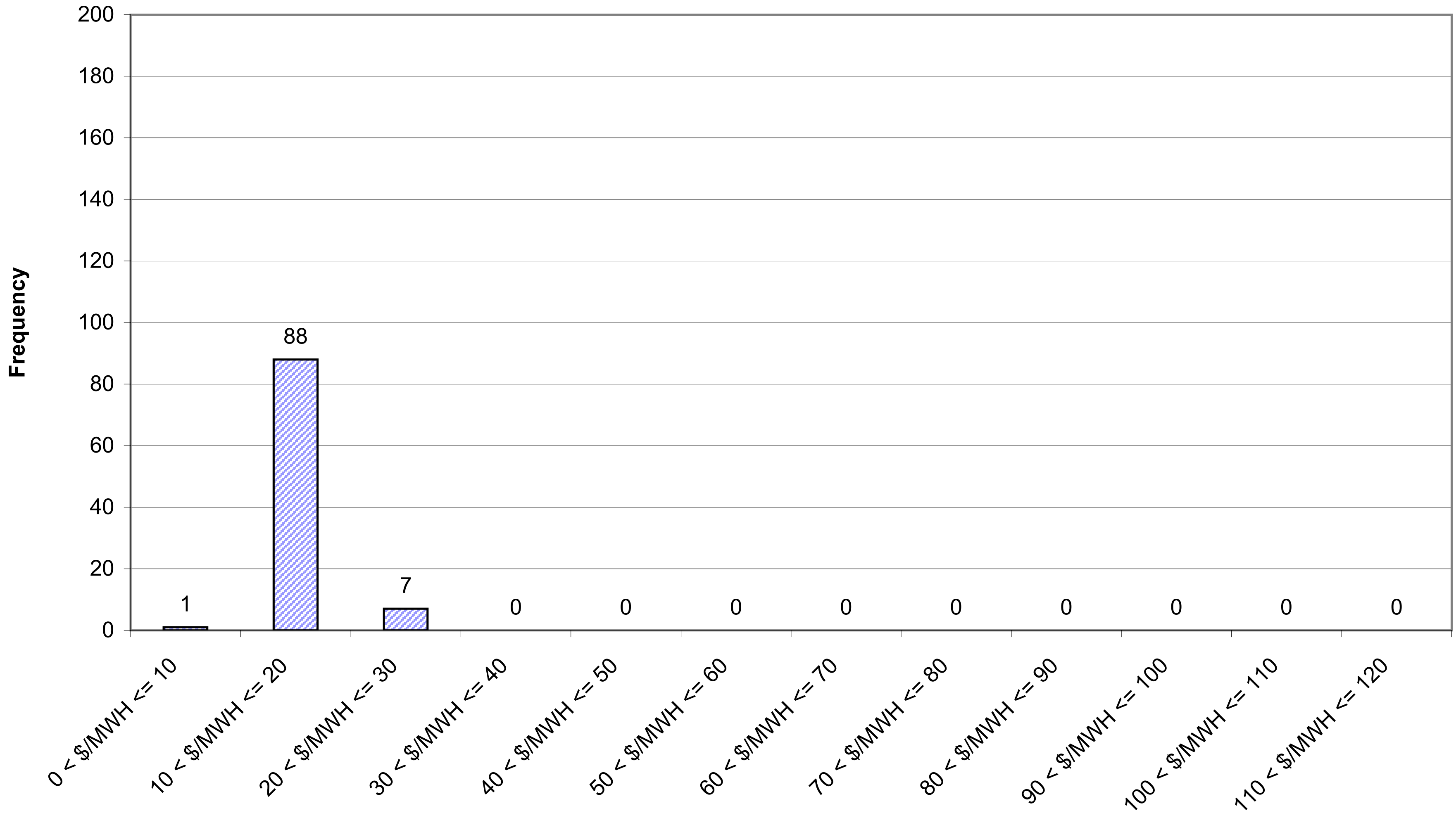
Idaho Power Projected Mid-Columbia Off-peak Electricity Prices
75th Percentile Hydro Condition (Water Year=1957)
N=96



Idaho Power Projected Mid-Columbia On-peak Electricity Prices
Highest Hydro Condition (Water Year=1983)
N=96



Idaho Power Projected Mid-Columbia Off-peak Electricity Prices
Highest Hydro Condition (Water Year=1983)
N=96



Staff Adjustments to Idaho Power Exhibit No. 13
Power Supply Expenses Normalized Using Idaho Power's Forward Price Curves from April 30, 2004

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
1 Hydroelectric Generation (mwh)	796,221.1	832,943.3	817,100.1	850,869.7	859,088.5	858,151.1	759,935.6	726,751.7	675,876.1	541,432.4	456,092.1	662,560.9	8,837,022.5
2 Bridger													
3 Energy (mwh)	438,772.7	378,579.5	442,661.3	391,177.1	327,570.9	326,888.8	455,772.4	455,868.7	441,499.2	456,599.6	441,577.7	456,158.0	5,013,126.0
4 Cost ($ x 1000)	$5,593.3	$4,826.0	$5,642.8	$4,986.5	$4,175.7	$4,167.0	$5,810.0	$5,811.2	$5,628.0	$5,820.5	$5,629.0	$5,814.9	$63,904.9
5 Boardman													
6 Energy (mwh)	35,892.5	31,118.0	36,441.9	32,832.6	29,961.8	0.0	38,327.3	38,725.3	37,546.0	38,791.7	37,544.3	38,754.2	395,935.6
7 Cost ($ x 1000)	$475.4	$412.2	$482.7	$434.9	$396.9	$0.0	$507.7	$513.0	$497.4	$513.9	$497.3	$513.4	$5,244.7
8 Valmy													
9 Energy (mwh)	162,669.0	145,085.8	78,685.9	114,741.2	151,563.5	148,155.1	163,064.5	163,062.4	157,894.3	162,805.5	157,745.1	163,173.8	1,768,646.1
10 Cost ($ x 1000)	$2,391.3	$2,132.8	$1,156.7	$1,686.7	$2,228.0	$2,177.9	$2,397.1	$2,397.1	$2,321.1	$2,393.3	$2,318.9	$2,398.7	$25,999.8
11 Danskin													
12 Energy (mwh)	10.1	13.8	35.6	8.5	137.6	238.7	149.3	166.9	11.0	5.7	7.0	20.3	804.6
13 Cost ($ x 1000)	$0.5	$0.7	$1.4	$0.4	$6.6	$11.3	$7.6	$8.0	$0.4	$0.3	$0.3	$0.8	$38.1
14 Fixed Capacity Charge - Gas Transportation ($ x 1000)	$272.0	$256.8	$272.0	$264.4	$272.0	$264.4	$272.0	$272.0	$264.4	$272.0	$264.4	$272.0	$3,218.4
15 Total Cost	$272.5	$257.5	$273.4	$264.8	$278.6	$275.7	$279.6	$280.0	$264.8	$272.3	$264.7	$272.8	$3,256.5
16 Forward Price Curve (Flat $/MWh)	**$52.65**	**$52.13**	**$51.61**	**$32.12**	**$30.86**	**$31.49**	**$48.46**	**$50.77**	**$47.08**	**$41.54**	**$43.84**	**$46.16**	**$44.06**
17 Purchased Power (Excluding CSPP)													
18 Market Energy (mwh)	10,978.3	2,425.5	2,126.6	976.7	18,390.4	40,600.1	44,999.7	31,717.5	12,398.6	1,019.0	19,820.4	25,362.5	210,815.2
19 Contract Energy (mwh)	0.0	0.0	0.0	0.0	0.0	32,400.0	33,480.0	33,480.0	0.0	0.0	0.0	0.0	99,360.0
20 Total Energy Excl. CSPP (mwh)	10,978.3	2,425.5	2,126.6	976.7	18,390.4	73,000.1	78,479.7	65,197.5	12,398.6	1,019.0	19,820.4	25,362.5	310,175.2
21 Market Cost ($ x 1000)	**$578.0**	**$126.4**	**$109.8**	**$31.4**	**$567.5**	**$1,278.5**	**$2,180.8**	**$1,610.3**	**$583.7**	**$42.3**	**$869.0**	**$1,170.6**	**$9,148.4**
22 Contract Cost ($ x 1000)	$0.0	$0.0	$0.0	$0.0	$0.0	$1,400.0	$1,500.0	$1,500.0	$0.0	$0.0	$0.0	$0.0	$4,400.0
23 Total Cost Excl. CSPP ($ x 1000)	**$578.0**	**$126.4**	**$109.8**	**$31.4**	**$567.5**	**$2,678.5**	**$3,680.8**	**$3,110.3**	**$583.7**	**$42.3**	**$869.0**	**$1,170.6**	**$13,548.4**
24 Surplus Sales													
25 Energy (mwh)	275,833.0	393,058.0	386,996.0	477,141.2	339,313.2	244,417.9	105,904.1	123,223.1	229,492.0	215,052.0	71,826.3	162,439.0	$3,024,695.7
26 Revenue Including Transmission Costs ($ x 1000)	**$14,523.3**	**$20,491.1**	**$19,973.9**	**$15,325.7**	**$10,471.3**	**$7,696.7**	**$5,132.5**	**$6,256.2**	**$10,803.7**	**$8,932.9**	**$3,149.0**	**$7,497.5**	**$130,253.7**
27 Transmission Costs ($ x 1000)	$275.8	$393.1	$387.0	$477.1	$339.3	$244.4	$105.9	$123.2	$229.5	$215.1	$71.8	$162.4	$3,024.7
28 Revenue Excluding Transmission Costs ($ x 1000)	**$14,247.4**	**$20,098.0**	**$19,586.9**	**$14,848.5**	**$10,132.0**	**$7,452.3**	**$5,026.6**	**$6,133.0**	**$10,574.3**	**$8,717.8**	**$3,077.2**	**$7,335.0**	**$127,229.0**
29 Net Power Supply Costs ($ x 1000)	**($4,936.9)**	**($12,343.2)**	**($11,921.5)**	**($7,444.2)**	**($2,485.2)**	**$1,846.9**	**$7,648.6**	**$5,978.6**	**($1,279.3)**	**$324.4**	**$6,501.8**	**$2,835.3**	**-$15,274.6**
30 Idaho Power Exhibit 13 Net Power Supply Costs ($ x 1000)	$3,318.8	$35.3	($441.5)	($1,786.6)	$1,176.5	$4,992.8	$9,944.2	$8,473.1	$3,489.8	$4,053.1	$7,906.2	$6,526.5	$47,688.1
31 Total Staff Adjustment ($ x 1000)	($8,255.7)	($12,378.5)	($11,479.9)	($5,657.6)	($3,661.7)	($3,145.9)	($2,295.5)	($2,494.5)	($4,769.1)	($3,728.7)	($1,404.4)	($3,691.2)	($62,962.8)

CERTIFICATE OF SERVICE

U E 167

I certify that I have this day served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-13-0070, to all parties or attorneys of parties.

Dated at Salem, Oregon, this 15th day of March, 2005.

Stephanie S. Andrus
Assistant Attorney General
Of Attorneys for Public Utility Commission's Staff
1162 Court Street NE
Salem, Oregon 97301-4096
Telephone: (503) 378-6322

UE 167
Service List (Parties)

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