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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of the Cincinnati Gas & Electric Company to Modify its Non-Residential Generation Rates to Provide for Market-Based Standard Service Offer Pricing and to Establish a Pilot Alternative Competitively-Bid Service Rate Option Subsequent to Market Development Period	)	Case No. 03-93-EL-ATA
In the Matter of the Application of The Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Certain Costs Associated With The Midwest Independent Transmission System Operator	)	Case No. 03-2079-EL-AAM
In the Matter of the Application of The Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Capital Investment in its Electric Transmission And Distribution System And to Establish a Capital Investment Reliability Rider to be Effective After the Market Development Period	)	Case No. 03-2081-EL-AAM Case No. 03-2080-EL-ATA

INITIAL JOINT BRIEF OF CONSTELLATION NEWENERGY, INC.,

MIDAMERICAN ENERGY COMPANY,
STRATEGIC ENERGY LLC, AND WPS ENERGY SERVICES, INC.
(aka OHIO MARKETERS GROUP)
AND CONSTELLATION POWER SOURCE, INC.,

June 22, 2004

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I. Procedural History and Parties

On January 10, 2003 Cincinnati Gas & Electric Company ("CG&E") filed to end its market development period for commercial and industrial customers and to institute a market based standard service offer with a competitive bid component (competitive market option or "CMO"). The application drew protests from numerous parties including: the Staff of the Commission; the Office of the Consumers' Counsel; industrial trade associations; and individual industrial customers. The CG&E application also drew protests from Constellation NewEnergy, Inc., MidAmerican Energy Company, Strategic Energy LLC, and WPS Energy Service, Inc., all of whom are Commission certificated competitive retail electric service providers ("CRES") who are active in Ohio. In accordance with the Commission's procedural policy of encouraging parties with like interest to consolidate their participation for hearing purposes, the four above listed CRES have consolidated their litigation of this case under the moniker "Ohio Marketers Group" or "OMG".

Approximately a year after CG&E's original filing, the Commission asked CG&E to consider a rate stabilization plan ("RSP") as an option for the post market development period in lieu of the CMO. On January 26, 2004, CG&E filed an application in the alternative to its CMO. The RSP application was also protested by several parties including the Ohio Marketers Group and Constellation Power Source, Inc. ("CPS"). CPS is a wholesale power marketer which sells electricity pursuant to a market based tariff on file with the Federal Energy Regulatory Commission ("FERC"). CPS sells wholesale electricity in several states, including Ohio, and has been particularly active in offering full requirements wholesale generation to serve standard offer customers in Maryland, Maine, Massachusetts and New Jersey. The combined CMO and RSP applications were set for hearing which was conducted in May of 2004. The Ohio Marketers Group and CPS were very active in the hearing and sponsored a total of four witnesses. During the hearing CG&E, the Staff of the Commission and several other Intervenors agreed upon a Stipulation which was presented to the Commission. Supplemental testimony both supporting the Stipulation and opposing it were filed. Initial and reply briefs were scheduled, and the following is the Initial brief sponsored by the Ohio Marketers Group and CPS.

II. Introduction – Statutory Framework

During the 1990's legislation was passed at both the federal and state level to restructure the electric generation industry. In response to the Congressional passage of the Energy Policy Act of 1992, the Federal Energy Regulatory Commission ("FERC") issued Order 2000, which was designed to provide open access to the nation's interstate electric transmission system and to provide for a more efficient use of the nation's generation and transmission assets. Similarly, the Ohio General Assembly passed Senate Bill 3, which effectively ended the franchise monopoly on the generation and sale of power for the investor-owned utilities and called on the Public Utilities Commission of Ohio to design transition programs by 2006 which would provide all retail customers with market priced generation.

Specifically, Section 4928.14(B), Revised Code calls for all electric utilities to conduct a competitive solicitation to determine the supplier of standard offer generation service and the price thereof; further, the statute mandates that the Commission, prior to December 31, 2004, issue rules on the subject. The Commission, in accordance with the above statute, did in a timely manner promulgate rules as to how this competitive bid-out should be conducted.[1] The Commission's competitive bid rules call for an open auction for the provision of standard offer generation service at the end of the market development period. All customers who have not made other arrangements for the supply of their generation service would be served from the power procured through the competitive solicitation.[2]

As a companion to the competitive bid out requirement, the General Assembly also provided in Section 4928.14(A), Revised Code for the potential for a retail market based priced offering in addition to the offerings of the Competitive Retail Electric Service providers ("CRES") and the competitive bid. The electric distribution utilities, though barred from offering bundled service, could offer a "market based" standard service offer which includes a firm supply of electric generation to all its customers. The above statement that the electric distribution utility "may" provide firm generation for the standard service offer is made because Section 4928.14, Revised Code clearly provides that an electric distribution utility can elect not to provide any generation and delegate out the market based standard offer generation supply to the competitive bid suppliers.

The goal of electric market restructuring in Ohio was to remove electric generation from the realm of a franchise monopoly service to a market based commodity. Senate Bill 3 prohibits the electric distribution utility from providing deregulated generation sales through the electric distribution utility other than the "safety net" bundled standard service offer[3]. The General Assembly was concerned that the

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[1] See the Order in Case No. 01-2164-EL-ORD
[2] OAC Rule 4901:1-35-03, Appendix B
[3] The electric distribution utility may form a separate affiliated corporation and participate in either the retail or whole power market.

monopoly wire service could be leveraged by the electric distribution utility to subsidize deregulated power sales and thwart competition. To insure against such an occurrence, Senate Bill 3 requires corporate separation of the franchised monopoly wire business from the deregulated power commodity business, prohibits anti-competitive behavior in the administration of the wire services, and as noted above, bans the bundled offering of power with wire service, save for the "safety net" standard service offer.

The intent of Section 4928.17, Revised Code is clear, for it calls for a Commission-approved corporate separation plan for any company engaged in both "the business of supplying a non-competitive retail electric service" (i.e., the regulated wire services) and <u>either</u> competitive retail electric service sales or "supplying a product or service other than retail electric service." Such a corporate separation affords protection that the monopoly wire service will not be used to finance ventures into the deregulated power market and counter balances the incentive that a combined power and wire company would have to favor its own power sales over the competition for access to wire service.

The General Assembly not only dictated a structure that is designed to curb such favoritism, but also explicitly stated that it is the policy of the State of Ohio to:

> ensure effective competition in the provision of retail electric service by avoiding anticompetitive subsidies flowing from a non-competitive retail electric service to a competitive retail electric service or to a product or service other than retail electric service and vice versa.[4]

The policy of the State of Ohio, as articulated in Senate Bill 3, fully embraces the open market model for the sale and use of power. In addition to providing for effective competition, Section 4928.02, Revised Code prescribes for the Commission the policy

[4] Section 4928.02(G), Revised Code

goals of insuring the availability of unbundled and comparable electric retail service[5] and a diversity of electric suppliers and supplies.[6]

Ohio's move towards a restructured electric generation market which is open and competitive, and offers all customers market based prices has been matched by a similar initiative on the federal level. Under the auspices of the FERC, the nation's electric generation and transmission assets are being organized into regional transmission organizations. CG&E, in accordance with the mandate of its transition plan, has joined the Midwest Independent System Operator ("MISO"), one of these regional transmission organizations, covering parts of eleven states and one Canadian province.[7] In accordance with its mandate as a regional transmission organization regulated by the FERC, the MISO has applied for authority to commence network based economic dispatching of power for all the utilities, including CG&E, in its footprint. The effective date of these changes is expected to be March 31, 2005, per a recent FERC decision[8].

Dr. Ronald McNamara, the Vice President of Regulatory Affairs and Chief Economist for MISO,[9] took the stand to explain how the network economic dispatching will work. Instead of each utility scheduling power from its contracted or owned units to meet projected demand at specified locations,

> What we will do when we commence the Day 2 operations is look at the entire footprint, and so we will look and see if there's cheaper units over here that can meet load there. And if there's transmission capacity available, those units will be employed or will show up as what we should

[5] Section 4928.02(B), Revised Code
[6] Section 4928.02(C), Revised Code
[7] IEU Exhibit 3
[8] 107 FERC 61, 191 at P. 3, issued May 26, 2004
[9] TR. Vol VI. p. 7

> actually dispatch in the centralized security constrained economic dispatch.[10]

Under centralized, security constrained, economic dispatch, MISO, not the individual utilities or current control areas within the MISO footprint, will line up the lowest bid units to meet the demand at any given time, considering resource availability and the constraints of the transmission system[11]. Because MISO will be balancing the demand and supply of generation on a regional basis, it will be MISO, not CG&E, that will be responsible in the Day 2 markets for balancing the deliveries of all suppliers, including both the competitive retail electric service ("CRES") providers and CG&E, with demand.

> We [MISO] will be coordinating power flows for the entire footprint, taking into consideration the effect of generation in certain areas, on transmission in other areas, as well as reliability constraints, voltage and so on. So we [MISO] will be dispatching across or sending a dispatch signal to the entire footprint, and using network models that reflect the entire footprint, not just a subset of that footprint. In fact, our network models will be the most complex of any in operation in the world. And that is where the benefits and gains come.[12]

Region based economic dispatching in essence separates the physical network operation of an electric grid from the financial responsibilities.[13] MISO will make sure that the right power plants run to meet system demand most efficiently, and the market participants -- load serving entities such as CRES providers and electric distribution utilities and customers -- will work out their financial arrangements via contracts. The

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[10] TR. Vol. VI, p. 14 -15

[11] Note that transmission constraints will be evidenced by congestion charges rather than transmission curtailment, thus further augmenting the financial nature of MISO Day 2 markets.

[12] TR. Vol. VI, p. 20

[13] Ibid at 25 -26

point-to-point transmission arrangements which predominate the market in Day 1 will largely be replaced with the network service from the MISO.[14]

MISO Day 2 was scheduled to launch December of this year. During the last week of May, however, the FERC delayed the implementation until March 1, 2005[15]. Dr. McNamara believes that the final FERC approvals would be received by then and that the implementation date would be kept.[16] Today, one other regional transmission organization – PJM -- and two independent system operators -- New England ISO and New York ISO-- are in a Day 2 mode of operation very similar to the MISO's tariff now pending before FERC. Several others markets, including California and ERCOT (Texas), are in the process of developing Day 2-type markets.[17]

In sum, the Congress and the Ohio General Assembly have restructured the electric industry so that generation is no longer a franchise monopoly-provided commodity with prices set under cost of service principles. Rather, the retail customers served within the service territory of CG&E are now able to select competitive retail providers that are part of a larger regional market. Thus, in Ohio, customers can shop for their electric provider free from any barriers from their wires company, with a safety net which is intended to provide them energy at market based pricing if they cannot or will not shop for their own power.

[14] "Effectively what centralized dispatch will do is negate the need to purchase point-to-point transmission service within the MISO footprint." TR. Vol. VI p. 20
[15] 107 FERC 61, 191 at P. 3, issued May 26, 2004
[16] TR. Vol VI, p. 38
[17] TR. Vol.VI, p. 36

III. CG&E is not a stand alone electric utility providing monopoly electric service only to a defined service area at cost of service rates. It operates today as a multi state power marketer with a combined regulated utility service operation in Ohio.

In accordance with Ohio law and Commission rules, CG&E must file an annual report indicating its costs and revenues from its electric service operations both inside and outside of Ohio. For the calendar year 2003 report filed in April of 2004, CG&E reported that it had $2.4 billion dollars in electric operating revenues for its activities in Ohio, and $4.4 billion dollars in electric operating revenues from its activities outside Ohio.[18] In other words, slightly more than 1/3 of CG&E's electric operation revenues came from its regulated service area operations in Ohio.[19] CG&E also files a comprehensive report on its electric service operations, called the FERC Form 1, with the FERC. In the FERC Form 1 for the year 2003,[20] CG&E lists all its major generating assets, the output and sales from those assets, and the revenues from its electric operating activities both for the current year (2003) and the previous year (2002). As it did in its 2003 Ohio annual report, CG&E indicated that its total electric service operating revenues totaled some $6.4 billion dollars and that this was a marked increase, some $2 billion dollars more than the previous year (calendar year 2002), in which sales were only $4.4 billion dollars. When asked about this tremendous growth in revenues, an amount equal to all of CG&E's Ohio electric operations, Mr. Rogers, the CEO, indicated:

> you can attribute to an increase in margin from our power trading business. You can attribute to an increase in margin from the sale of a non-regulated generation to others, because, as you know, we had fixed prices in Ohio.

[18] OMG Exhibit 8

[19] All of CG&E electric tariff sales would be in Ohio, but the Ohio sales figure would also include wholesale transactions in Ohio.

[20] OMG Exhibit 2

> And its primarily attributable to our marketing efforts to sell power to other wholesale customers in the region.[21]

As the revenue numbers for 2002 and 2003 indicate, CG&E has taken full advantage of Senate Bill 3 and now uses CG&E, the Ohio operating utility, as the coordinating and booking entity for much of the centralized sale of power for the Cinergy utilities[22]. Filings at the FERC reveal that not long after passage of Senate Bill 3, CG&E filed before and received approval from the FERC to jointly dispatch the regulating assets that it held in the CG&E name as well as those of its sister operating affiliate, PSI. OMG Exhibit 6 is a copy of the Joint Generation Dispatch Agreement approved by FERC. As Mr. Rogers[23] explained, the operation of Joint Generation Dispatch Agreement allows CG&E to use economic dispatch (similar to what MISO will do for the region under Day 2 operations) from the Cinergy-held generation assets and contract rights for the needs of the three Cinergy operating companies, Union Light Heat and Power ("Union"), PSI, and CG&E, as well as to sell the surplus power off system in the wholesale market. It is clear from the cross-examination that the generating assets still titled to CG&E are used and will continue to be used to meet sales obligations that go far beyond the jurisdictional requirements of the Ohio jurisdictional customers. In addition to the off system sales,[24] the generating assets owned by CG&E are and will be used to fulfill a full requirements contract for Union, a Cinergy utility subsidiary in Kentucky. The cost for the power sold

[21] TR Vol. II, p. 69
[22] PSI Energy, Inc., Union Light Heat and Power and CG&E
[23] TR Vol. II, p. 62 "but this joint dispatch is designed for the purpose of being able to maintain the highest level of reliability with the system that we have, but the dispatch is both regulated and non-regulated generation."
[24] TR Vol. II, p. 64

by CG&E to Union is established via a contract approved by FERC which uses a fixed rate formula which cannot be amended until the termination of that agreement.[25]

On cross-examination, Mr. Rogers indicated that there were plans to transfer generation ownership from CG&E to Union.[26] The transferred units will include the base line coal generation units known as East Bend, and Miami Fort Unit No. 5, as well as the Woodsdale gas fired peaking station. Mr. Rogers also indicated that the commitment for Union today more or less equaled the output of these three units.

Two of the generation units which CG&E plans to transfer the title to Union give rise to part of the emission allowance, and investment in environmental compliance equipment, which CG&E wishes to incorporate as part of a Provider of Last Resort ("POLR") charge, which is non-bypassable, even for customers that shop. Further, all three units have projected investments in generation related homeland security expenditures which CG&E seeks to include in its POLR charge (See paragraph 3 of the Stipulation Joint Exhibit 1).

Similarly, any and all sales of power from the units owned by CG&E for off system sales will have their emission allowances, homeland security costs, and environmental compliance costs paid for by the Ohio jurisdictional customers as part of the POLR charge.

Because of the deregulation provisions in Senate Bill 3, CG&E does not currently dedicate the output of any of the power plants it holds title to exclusively for the jurisdictional customers of CG&E. CG&E's sister affiliate, PSI, is still under cost of service type regulation. PSI's generation, though dispatched by CG&E under the Joint

[25] TR. Vol. II, p. 41
[26] TR. Vol. II, pp. 40-41

Generation Dispatch Agreement, must credit back to PSI's Indiana jurisdictional customers some of its off system sales.[27]

IV. Issue No. 1: CG&E's request for an indefinite waiver of its obligation to transfer its generating assets to an electric wholesale generator by December 31, 2004 as called for in its approved transition plan should be denied.

CG&E had originally planned on transferring its electric generating assets from the utility company to an electric wholesale generator at the start of the market development period. As noted in OMG Exhibit 6 (the Joint Generation Dispatch Agreement), CG&E informed the FERC that it was forming CPI Investments ("Investments") as its electric wholesale generating arm which would serve as wholesale energy company with title to generation. Investments would then enter into a full requirements contract with CG&E for its utility service area power needs.[28] Similarly, in Case No. 01-2389-EL-UNC, CG&E requested Commission authority to contract with an affiliated exempt wholesale generator ("EWG") for its full power demand.

This plan, originally scheduled for 2001, was subsequently changed in the transition case, Case No. 99-1658-EL-ETP, where CG&E asked for an extension of time through December 31, 2004 to avoid certain costs associated with the transfer in 2001 versus 2004. CG&E now requests, as part of Paragraph 14 of the Stipulation,[29] that it be relieved indefinitely from its obligation to transfer its generating assets to an EWG. For procedural, legal, and policy reasons, this request should be denied.

Procedurally, the requirement for CG&E to transfer its electric generating assets to an exempt electric wholesale generator was part of the Case No. 99-1658-EL-ETP Stipulation adopted by the Commission in its August 31, 2000 Opinion and Order. Any

[27] TR. Vol. II, pp. 65-66
[28] OMG Exhibit 6 – the sixth "whereas" clause
[29] Joint Exhibit 1

amendment to the Stipulation should procedurally be filed in Case No. 99-1658-EL-ETP so that all the parties of record who participated in that proceeding and who depended upon or relied up that provision of the Stipulation could be heard as to whether it should be lifted. Two members of the Ohio Marketers Group, NewEnergy Midwest LLC (who subsequently became Constellation NewEnergy, Inc.) and WPS Energy Services, Inc. were parties to the transition case and do not approve of the indefinite waiver requested in paragraph 14 of the Stipulation in the matter at bar.

By requesting the retention of its generating facilities, CG&E is asking the Commission to approve, within the regulated company, potentially two activities that cannot be lawfully engaged in simultaneously with the monopoly wire service – non-competitive retail electric sales and the wholesale electricity generation sales. Section 4928.17(A), Revised Code, states in part that no electric utility, or combination of electric utility and affiliate shall be both,

> ....in the business of supplying non-competitive retail electric service and supplying a product or service other than retail electric service, <u>unless the utility implements and operates under a corporate separation plan that is approved by the Public Utilities Commission ...</u>"] (emphasis added).

CG&E, as the monopoly franchised provider of wire service in its service territory, must continue to supply distribution service which is a non-competitive retail electric service. As noted in Section II above, CG&E also operates as a wholesale electric provider selling power to Union and making off-system sales in the wholesale market. Given the clear language in Section 4928.17, Revised Code, CG&E must now separate its generation facilities in a corporate separation plan approved by the

Commission which meets the requirement of not only Section 4928.17, Revised Code but also of Section 4928.02, Revised Code.

Before the Commission can approve a corporate separation plan, it must be demonstrated, at a minimum, that the competitive provision of electric product or service is conducted in a "...fully separated affiliate of the utility, and the plan includes separate accounting requirements, the code of conduct . . . and such other measures as are necessary to effectuate the policy identified in Section 4928.02 of the Revised Code."[30] Furthermore, the corporate separation plan must protect the public interests by preventing unfair competition, preventing the abuse of market power and assuring that any affiliate or division is not afforded any undue preference or advantage. Section 4928.17(A)(2) and (3), Revised Code.

The General Assembly further articulated its concern that the monopoly right to provide wire service could be abused by explicitly stating that the purpose of the competitive retail service policy is to "insure effective competition in the provision of retail electric service by voiding anticompetitive subsidies flowing from a non-competitive retail electric service to a competitive retail electric service or to a product or service other than retail electric service, and vise versa." Section 4928.02(G), Revised Code.

The matter at bar underscores the wisdom of the General Assembly's corporate separation structure. First, separation of the regulated utility service from the deregulated service protects distribution assets which have been publicly dedicated from exposure from financial risks from non-utility activities. As noted in Section II above, the public utility, CG&E, has a dollar exposure from its energy trading activities that far outstrip its

[30] Section 4928.17(A)(1), Revised Code

revenue flow from its regulated wire service. Today, if the separation plan called for in Transition Case Stipulation is waived, there is no Commission prohibition on the use of the utility assets to secure CG&E's general obligations, including those from its energy trading activities. The assets of the public utility service should be in a separate entity from that of the energy trading or generation business.

As noted above, CG&E plans to make the jurisdictional customers of the utility pay for the emission allowances, and the environmental compliance equipment on the assets to which the utility holds title. CG&E also has no plans to credit back the revenues coming from the sales to Union or its off-system sales from any of the generation owned by CG&E which will be supported by the POLR charge. When asked why a credit should not flow back to the Ohio rate payers for equipment that was used to make off-system sales or sales to Union Light Heat and Power, Mr. Steffens responded that it would be difficult, if not impossible, to account for which generation units were used for a particular sale, as well as his belief that the amount would be deminimus.[31]

When one considers that CG&E is essentially dispatching the generation units that it and PSI own to meet the needs of the three Cinergy operating companies as well as conducting off-system sales, one would have to agree with Mr. Steffens that tracking and accounting for such sales would be difficult if not impossible. It would not be impossible, though, if CG&E were to follow the statutory requirements and the plan originally designed as part of the transition case for transfer of the generation assets to an EWG affiliate and the granting back of a full demand contract, similar to what is done today for Union.

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[31] TR Vol. IV p. 92 -93

Without an audit, it is impossible to know whether having the Ohio jurisdictional rate payers pay for the emission allowances, environmental compliance equipment, and homeland security costs for generation being sold off-system or to Union creates a subsidy from the Ohio jurisdictional customers to the wholesale customers of CG&E and /or customers of Union or to the shareholders of CG&E. Either way, it violates the clear intent of Section 4928.17, Revised Code which calls for separation of the utility activities from the non-regulated activities as Section 4928.02 (G), Revised Code which prohibits subsidies and anti-competitive action.

In light of the foregoing, the Commission should deny the requested waiver in paragraph 14 of the Stipulation, and also require CG&E to reduce the amount of the POLR per kWh by the dollar value of the emission allowances, environmental compliance cost and homeland security costs associated with the East Bend,[32] Miami Fort No. 5 and Woodsdale units as such units (or their energy equivalent) will not be utilized to provide POLR service for Ohio consumers.

V. Issue No. 2: The cost of environmental compliance, security for power plants and power production taxes are generation expenses and, as such, should be part of the generation component of the standard service offer, not the POLR charge.

The OMG and CPS do not object to environmental compliance expenses and homeland security costs for certain of CG&E's plants being included as part of the market based standard offer; however, OMG and CPS do object to these expenses being included as part of the POLR charge.[33] As described in Mr. Lacey's supplemental

[32] East Bend is listed by name as having an environmental compliance capital expense for 2001 and an operational and maintenance expense as well as a Kentucky tax expense – See Joint Exhibit 1 – Attachment Exhibit 1 JPS-4.

[33] OMG does object to the inclusion in any manner of the capital expenses for pollution control equipment, the operational and maintenance expenses for pollution control equipment and SOx emission allowances

testimony,[34] any entity which generates electric power in the United States is going to have to pay the cost of complying with all environmental requirements, including the cost of purchasing and installing pollution control equipment, operating and maintenance expenses for such pollution equipment, and protecting the power plant from domestic and foreign terrorists. The price of power when purchased in the open market reflects these costs, for power cannot be generated in this country without the necessary investment in environmental control and security.

CG&E, as part of its RSP, asks for increases each year to cover the increase in costs for environmental compliance over the pre market development cost levels for both capital and operation and maintenance costs. If CG&E was using a proper market based pricing model, such expenses would already be included in the market based generation price, so a stand alone adder to capture the cost of complying with the nation's pollution control and homeland security standards would not be necessary. The RSP, though, does not start with what a willing buyer would pay a willing seller for power. Instead, as delineated by service tariff and tier in Stipulation Exhibit 3, CG&E calculates the cost of the generation component as "big G", defined by Witness Steffens as the unbundled generation rate from the transition case,[35] minus both the Regulatory Transition Charge ("RTC") and the rate stabilization charge ("RSC"). In sum, the generation charge for the so called market based standard service offer is the cost of generation, as unbundled in the ETP case from the last CG&E rate case, minus two non-power related costs -- the RTC and RSC. Since the generation rate for all tariffs is now substantially below the cost

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for the East Bend, Miami Fort No. 5 and Woodsdale units because they represent the equivalent of the environmental control and security expenses being used to serve the Union customers and not being used for Ohio jurisdictional customers.

[34] OMG Exhibit 13, Supplemental Direct Prepared Testimony of Frank Lacey

[35] TR Vol. IV, p. 12

of generation from CG&E's last rate case, it is not surprising that CG&E seeks an adder to cover environmental compliance cost increases and homeland security costs.

Unfortunately, rather than classify environmental compliance costs and generation protection under homeland security for the generation costs that they are, paragraph 3 of the Stipulation asks that these costs be made part of a non-bypassable POLR rider. In other words, CG&E is asking that all customers pay – whether they take power or not from CG&E's generation units – for the costs of CG&E's generation plant emission allowances, environmental compliance costs, and homeland security costs.

The placement of the environmental compliance and homeland security costs in a non-bypassable rider is both inequitable and anti-competitive. It is inequitable because customers who buy their power from a CRES provider will have to pay as part of their generation price to the CRES provider the emission allowances, environmental compliance, and homeland security costs for the generation the CRES provider procures.[36] To make customers who are already paying the environmental costs and homeland security for the power they purchase and use also pay for part of the environmental compliance and homeland security cost for power they don't use, is inequitable on its face.

Second, failing to include in the cost of generation what clearly are generation costs sends an artificially low price signal to retail customers as to the cost of the standard service power they are buying. In other words, since the "price to compare for generation" has part of the cost of environmental compliance and homeland security omitted and partially paid by customers who don't take power from the units, a subsidy is created flowing from the shopping customers to standard service offer customers.

[36] OMG Exhibit 11, Direct Prepared Testimony of Mr. Frank Lacey, p..8

Section 4928.02 (G), Revised Code expressly prohibits cross subsidies from non-competitive services charge to generation which is a competitive service. Further, Section 4928.14(A), Revised Code requires that the standard service offer be "comparable and nondiscriminatory"; favoring the standard service offer over CRES provider service is discriminatory and makes the service not fully comparable.

CG&E has taken the position that it is not inequitable to place part of the cost of environmental compliance and homeland security in the POLR charge since the customers who are shopping have the right to return to the standard service offer. First, it should be distinguished that only commercial and industrial customers who purchase the Rate Stabilization Service and pay the RSC have the right to return. Customers who do not sign up for the Rate Stabilization Service (limited to 25% of each class in the Stipulation) come back at CG&E's highest affiliate cost of power.

CG&E is not establishing a set price for the returning customer, but only charging them the incremental cost of power to CG&E when they return. It seems illogical to charge returning customers (who will already pay the highest price paid by CG&E) the cost of equipping specific generation units with environmental compliance equipment, and homeland security when those units are not pledged to serve the returning customer. Further, even it the CG&E units are used to supply the returning commercial and industrial customer, that customer will be charged the highest incremental cost, not the cost from the unit the customer has been supporting in part via the POLR charge.

Finally, the failure to remove that part of the environmental compliance and homeland security costs of CG&E titled generation facilities from CG&E retail customers who do not take power from CG&E does not mean that CG&E will fail to recover all its environmental and homeland security costs. Every kWh which a CG&E jurisdictional customer fails to buy is a potential kWh that CG&E can sell on the wholesale market. If the price of the market based standard service offer is truly a market based price, then CG&E ought to be indifferent as to whether an Ohio jurisdictional customer buys the kWh or an off system customer buys the kWh.

CG&E may argue that it may not get as "robust a price" in the economy dispatch market for generation being held aside for CG&E customers that shop as it will collect under the standard service offer rates. This is true for customers that take the rate stabilization service, but those customers will be paying CG&E the RSC charge which should make up the difference. As for customers who do not take the rate stabilization service, they must sign a contract with CG&E stating that they will not return. Thus, CG&E should be free to sell the non-rate stabilization customer's generation under a long term contract similar to or better than the commitment of a tariff customer.

VI. Issue No. 3: CG&E's Proposal, which requires returning shopping customers who do not buy the RSC to pay the cost of purchase power of any Cinergy affiliate if that is higher than CG&E's must be rejected.

In its application, CG&E has proposed that shopping customers who do not buy the RSC and return to the CG&E standard service offer must pay the highest purchase power costs CG&E incurs to procure the power, or the price paid during the same time period any affiliate of Cinergy if that is higher than the CG&E price. Practically, this subjects the returning customer to not only the highest power prices in CG&E's service area but also Union's service area in Kentucky or PSI in Indiana.

Recently, the Commission was faced with a similar issue in Case No. 03-2144-EL-ATA, <u>In the Matter of the Applications of Ohio Edison Company, The Cleveland</u>

Electric Illuminating Company, and The Toledo Edison Company for Authority to Continue and Modify Certain Regulatory Accounting Practices and Procedures, for Tariff Approvals and to Establish Rates and Other Charges Including Regulatory Transition Charges Following the Market Development Period, Opinion and Order, June 9, 2004 at pages 33-35. FirstEnergy's proposed plan contained a provision which subjected returning customers to pay not only the highest cost of power purchased by the providing FirstEnergy Ohio utility, but to the average of the highest purchase power cost incurred by any affiliate of FirstEnergy to serve any of its customers in any of the states it serves.

The Commission found that the "relevant market for analyzing and specifying market pricing was that served by the EDU." See the June 9, 2004 Opinion and Order in Case No. 03-2144-EL-ATA, at page 34. The Commission should make a similar finding in this case. The relevant market for analyzing and specifying market pricing should be that served by CG&E, not the highest price of all of the affiliates in the Cinergy system. CG&E's proposal must be rejected.

VII. Issue No. 4: The cost of reserve margin is a generation expense and, as such, should be part of the generation component of the standard service offer, not the POLR charge.

On rare occasions a generation unit that is scheduled for operation will unexpectedly shutdown, or other unforeseen conditions will cause power that is scheduled for use to fail to be delivered where planned. To address this contingency, ECAR, the NERC reliability area in which the CG&E service territory is located,[37] sets reserve requirements so that each load serving entity, be they a utility or a CRES,

[37] MISO is currently developing a resource adequacy plan which may impose new or additional short and/or long term reserve requirements.

arranges for additional capacity to be ready to cover for a loss of planned generation.[38] Reserve margin requirements can be met with generation units that lay idle waiting for an emergency, or by contracting with other wholesale generator(s) for a contractual right for the required back-up power. Today, CG&E's titled generation units, minus its contractual commitments to Union, total less than CG&E's full demand; the shortfall, as well as some reserve margin, is covered by contracts.[39] In fact, as noted by CG&E witness Rogers, power is contracted with one of the parties to this proceeding.[40]

> To meet our reserve margin requirements, to be a prudent operator, we use a blend of products. Some of the products are capacity backed firm that are from units that are connected to our system. Some of it is the purchase of calls in the market with the stated strike price, which I think some of those from your clients, actually, I don't know quite where they get their capacity, because I don't believe they own any in Ohio. And some of it we purchase 5 by 16 products.

If CG&E were to elect to fulfill its obligation under Section 4928.14, Revised Code, and out-source the standard offer generation supply obligation to the winners of a competitive bid, the competitive bid supplier(s) would have to include the cost of reserve margin as part of their bid. In its original filing in this proceeding, the CMO MBSSO, reserve margin was not a separate added cost, but rather captured in the market based pricing. The OMG and CPS agree with that approach, for all CRES or wholesale providers in the 11 state MISO footprint will have to meet ECAR and MISO reserve margin standards. CG&E, however, did request a POLR charge of a couple of mils per

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[38] OMG Exhibit 11, Direct Prepared Testimony of Frank Lacey, pp. 8-9; OMG Exhibit 14, Direct Prepared Testimony of Thomas Gantzer, pp. 5-6

[39] Q. Does Cincinnati Gas & Electric have to buy either capacity or generation in order to meet its load in addition to the generation that it owns?

A. In order to meet its projected peak, as well as to have capacity to stand ready to service those who return, and additionally maintain a 15 percent reserve margin, 15 to 17 percent reserve margin, we have to purchase additional capacity. (Cross examination of Mr. Rogers, TR. Vol. I p. 48.)

[40] TR. Vol. II, pp. 49-50

kWh with which it planned to purchase capacity options to ensure that CG&E had enough capacity to cover an unexpected return of a shopping customer at a time when CG&E was at peak.[41] It is unclear from the CMO MBSSO application whether CG&E was only buying options for the peak months when, unlike the rest of the year, it would not have unused capacity, or if the estimated cost was for a 12 month option.

In stark contrast to the way reserve margin costs are treated in the CMO MBSSO, in the RSP application \ Stipulation a separate reserve margin cost is part of an independent POLR charge applied to all retail customers – those who buy power from CG&E as well as those who do not. The reserve margin in the RSP POLR is not the modest cost of a seasonal option. Instead, CG&E asks for a reserve margin of 17% of its anticipated total peak demand on its system, which includes both shopping as well as non-shopping load. This 17% reserve margin over peak is then priced out at some $64 per kw-year.[42] Mr. Steffens calculated the cost of reserve margin in the POLR to exceed $52 million dollars for the first year, close to half the variable POLR charge.[43]

What do shopping customers get for roughly half the variable POLR charge they must pay? Nothing, if one is a customer who elects not to take the rate stabilization service. Nowhere in the RSP does CG&E guarantee the shopping customer that it will have capacity if the customer returns despite the payment of the reserve margin component of the POLR. In fact, the Stipulation states just the opposite. It requires the shopping customer who does not also take the rate stabilization price service to prepare to be disconnected.

[41] CG&E Application, Case No. 03-93, January 10, 2003, p. 7
[42] Joint Exhibit 1 – Exhibit I attachment JPS - 7
[43] Ibid.

> [Consumers] that present CG&E with an acceptable contract as described above, must sign a contract with CG&E agreeing that if their contracting CRES provider defaults the customer may only return to service from CG&E at the market rate, or, <u>if no generation is available, be subject to disconnection</u>.(emphasis added)[44]

Since commercial and industrial customers are not assured of firm service, they cannot appropriately be charged a reserve margin fee designed to pay for additional capacity in order to insure firm service.

This brings us to the discussion as to whether CG&E should purchase capacity rights beyond the needs of the standard service offer customers to stand ready to take back the shopping customers whose CRES providers fail. Such a service appears to be unnecessary after MISO Day 2, for, as Dr. McNamara explained, the task of balancing demand and generation after MISO Day 2 is the task of the MISO, and market participants that are provided generation will be charged according to the MISO tariff structure. Further, the load serving entities, both CG&E and CRES providers, will have to post the necessary financial security with MISO to ensure payment by the under delivering load serving entity to the supplier that MISO using economy dispatch uses to fill in the under delivery:

> Q. Would it be the Midwest ISO, then, that would be assessing this penalty and collecting the money and paying whomever is the supplier, the generator who's filling in?
> A. It's in the tariff, and it's paid. I mean, yes, the generator who is filling in will get paid, and the deviation penalty is part of the tariff, so it's not a discretionary part on us; its accepted.
>
> Q. MISO in essence, will run the bank, take care of this, assess the penalties
> A. We're the middleman; we will flow through.
> TR. Vol. VI p. 34

[44] Joint Exhibit 1 paragraph 4 (D)

MISO is scheduled to commence its Day 2 markets on March 1, 2005. That is nine months before the end of the market development period for residential customers on CG&E. Under the proposed Stipulation, residential customers will not be paying the POLR, including the reserve margin component. Similar to the residential customers, the Stipulation provides that commercial and industrial customers who are currently shopping will remain under the shopping credit paradigm for 2005 and, thus, will not have to pay the RSC charges. In cross examination, Mr. Steffens testified that the commercial and industrial customers who continue through 2005 using the market development shopping credit method of compensating CG&E for its service, as opposed to post-market development period distribution charges, RTCs and riders, will not pay the RSC charges. Mr. Steffens indicated that the same was not true of the "variable portions" of the POLR including the reserve margin.[45] During the market development period, commercial and industrial customers who shopped and paid CG&E a fee based on their bundled rates minus a shopping credit had the right to return to the standard service offer as a part of that bundled fee. Thus, it stands to reason that if such commercial and industrial customers in 2005 continue to pay the bundled rate with the same shopping credit, they should get the same service. Thus, commercial and industrial customers who, like their residential counterparts, under the Stipulation will be remaining in the market development shopping credit paradigm, should not pay the post-market development POLR fees.

In sum, reserve margins are a reliability cost of providing generation. All load serving entities must meet the same minimum standards set by ECAR and MISO, which

[45] TR. VOL IV p.105

are likely to change over time to address the then current reliability needs of the region. Since reserve margins are a cost of providing generation, the cost of reserve margins should be in the generation component of the standard service offer, not in the non-bypassable POLR charge. Putting the reserve margin cost in the POLR charge subjects shopping customers to paying greater reserve margin costs though their load poses no greater risk. This is particularly true for the shopping customers who do not elect to take the rate stabilization service, for they appear to be ineligible to receive the full benefits of the reserve capacity for which they are being asked to pay.

No strong case has been made for the proposition that CG&E should purchase an additional amount of reserve capacity to cover a defaulting CRES provider. While it is true that in MISO Day 1 markets, it is CG&E that would be responsible for securing capacity if the shopping customers CRES provider fails, MISO in the Day 2 market, though its balancing and dispatch operations, will ensure that sufficient capacity is available to be provided to CG&E if CG&E becomes responsible for returning customers. Further, Day 2 is scheduled to commence prior to the time that the residential customers, and, arguably, the commercial and industrial customers who are currently shopping, leave the market development period pricing paradigm.

Finally, there is no evidence in this record that capacity will not be available in the market in 2005 or beyond should a CRES provider default and send the retail customer back to CG&E for the standard service offer. In fact, according the CG&E witness Rose, the Cinergy Hub appears to be the most liquid trading point in the country.[46] Since the Stipulation clearly has the returning customer paying the incremental cost of obtaining back up service, CG&E is at no financial risk other than

[46] CG&E Exhibit 7, Direct Prepared Testimony of Judah Rose, pp. 34-36

collecting payment. As for what may, or may not, be the collection of higher energy costs for returning CRES customers over what CG&E would charge the same customer for the standard service offer, CG&E is secured in two ways. First, CG&E has, in accordance with the financial security provision of its CRES Tariff, security from the CRES provider to make it whole for precisely this risk. Second, as noted in Witness Gantzer's testimony,[47] the CRES providers who are active in CG&E's service area today have credit ratings that are equal or superior to those of the electric distribution utilities in Ohio.

VIII. Issue No. 5: The Rate Stabilization Service should be a discrete service that retail customers can elect to purchase or not purchase. No customer should be mandated to purchase the Rate Stabilization Service.

Under the RSP, as modified by the Stipulation, 75% of the customer load in each class must purchase CG&E's rate stabilization service and pay the RSC charge. The quid pro quo for a retail customer paying the RSC is the right to return to the standard service offer at the then current standard service rate. Conceptually, the rate stabilization program for a shopping customer does not seem to provide significant value. After all, the only time customers would utilize the rate stabilization service would be if (i) their CRES provider defaulted; (ii) they returned to CG&E; and (iii) the market price for power has increased markedly over the standard service offer price. Unless all three contingencies come to pass, retail customers will not make use of the right to return at the standard service offer price. If the CRES provider does not fail, then the customer will continue to purchase power from the CRES provider. Since the customer is unlikely to have contracted with the CRES provider if the contract is higher than standard service offer, the customer will always better off with the CRES provider. If the CRES provider

[47] OMG Exhibit 14, Direct Prepared Testimony of Thomas Gantzer, pp. 4-6

defaults on a delivery under MISO Day 1, CG&E will cover and bill the CRES provider, so once again the customer has the superior bargain over the standard service offer rate. In MISO Day 2, the risk is the same except that it will be MISO billing the CRES provider instead of CG&E. If the CRES provider defaults, and cannot pay the cover, then the customer may return to the standard service offer if it is below the market price.

Is it likely that the market price during the RSP period would greatly eclipse the standard service offer rate? There is good reason to think that it may not. After all, the standard service offer is initially set at the market rate for generation. To that current market rate, all fuel increases over the prices levels in 2000 will be added in, plus each year of the RSP there will be an increase in the POLR fee of 6% to 8% to cover increases in environmental compliance and homeland security costs.

No witness clearly articulated the benefits of the rate stabilization service or quantified the risk a customer could avoid by signing up for the rate stabilization service with its RSC fee. On the other hand, Mr. Lacey summed up the obvious shortcomings.

> "....The RSC is nothing more than an extremely expensive insurance policy to protect against the unlikely event that one's CRES supplier defaults and the financial security posted by the CRES supplier with both the MISO and CG&E proves insufficient.[48]

While the benefits of the rate stabilization service seem limited, the RSC fee is far from modest. The RSC is set at 15% of "g." No studies, projections, cost justifications or even summary of how that price was arrived at is in this record, other than Mr. Steffen's testimony that it seemed a reasonable price.[49] Since Senate Bill 3 did not require a rate stabilization service, nor is such a service a practical necessity for full retail

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[48] OMG Exhibit 13, Supplemental Testimony of Frank Lacey, p. 4
[49] TR. Vol. IV, p. 97-98

electric service, pricing of the RSC poses little harm to the public so long as it a voluntary purchase. Paragraph 4 of the Stipulation, however, makes the RSC mandatory for 75% of the load for each customer class. If the rate stabilization service was a good service at a fair price, there should no need to legally compel customers to buy it. The first suspicion is that the RSC is designed as a cross subsidy to pay for other parts of the RSP program. Since it is assessed on a kWh basis, the immediate concern for a CRES provider is that it is a generation cost subsidy. Such a subsidy would expressly violate Section 4928.02 (G), Revised Code which prohibits subsidies from the regulated services to the non-regulated service. A cross subsidy from the RSC charge for generation would also violate the "non-discrimination" and "comparable service" requirements of Section 4928.14 (A), Revised Code as well as Commission rate design policy. Finally, on its face, offering a better deal to some but not all of similarly situated customers seems to violate Commission principles of discrimination on its face.

CG&E may argue that during the Market Development Period, it offered incentive rates to the first 20% of each class to get them to shop. That was in response to a statutory scheme that mandated 20% shopping and gave the Commission the right to adjust market development rates if the 20% goals were not met.[50] No similar statutory mandate is being fulfilled by the 25% exception to the mandatory rule that customers must buy a discretionary service. What is lacking is a reason for the restraint of the 75% of the customer load.

For the post-MDP, CG&E offered no basis for the continuance of ceilings on customer switching or support for the creation of new customer switching suppression mechanisms. While targeting only 20% of a customer class *may or may not have been* an

[50] Section 4928.40, Revised Code

appropriate practice during the MDP's "transition" period, there is no reason to continue such practices in the post-MDP world. Given SB 3's corporate separation requirements, protections against undue affiliate and distribution company advantages, and the prohibition against anti-competitive practices, it is clear the statute envisioned a neutral shopping environment with the potential for unfettered, if not robust, shopping. Devising plans for '05-'08 that in effect limit shopping not only contravenes the statutory framework, but revokes the retail customer's freedom.

Mr. Steffens testified that RSC was designed only to meet the cost of providing the rate stabilization service, and was not needed as a subsidy.

> Q. I want to go a level deeper than that. I am asking you, did you specifically design the RSC to produce revenue that's greater than the foreseen cost of the service in order to pay for other aspects of the program?
>
> A. You ask did we specifically do that, and the answer is no. TR. Vol. IV p. 100

The expressed policy for restructuring, as noted in the first section of this brief, was to present customers with supply and supplier options, provide innovative new products, assure market based rates by revoking the franchised monopoly over the sale of generation by the utilities, and institute protections against anti-competitive behavior. A plan that requires 75% of the customers to buy a service they may not want or need violates those statutory requirements and is poor public policy. Finally, assuming Mr. Steffens is correct and the RSC is not designed to finance anything other than the rate stabilization plan, CG&E should not be harmed if it allows customers who do not want the rate stabilization program to decline the service in exchange for CG&E not providing the service to them.

IX. Issue No. 6: Unless the generation costs for environmental compliance, homeland security and reserve margin are incorporated and made part of the generation component and thus bypassable, the Stipulation will fail to meet the Commission's requirement that a rate stabilization plan must promote market development.

Section 4928.14 (A), Revised Code requires the "market based standard service offer" to be market based. As more fully discussed in the section that follows, the rates that are being offered in the RSP do not evolve from what a willing buyer and willing seller would agree upon and thus cannot be considered "market based." The RSP price to compare for generation, or "g," is calculated by taking the unbundled cost of generation from the transition case less the regulatory transition costs[51] and less the RSC charges. Thus, what we know is that "g" is not based on any actual sales, and that it is less than unbundled cost of generation from the last rate case. Witness Lacey quantified for the commercial and small and medium size industrial customers just how much lower "g" is from the mid-1990's price for generation as unbundled in 1999. Attachment FL-3[52] looks at the DS Tariff Schedules and the DP Tariff schedules for a variety of load factors and finds that "g" is some 19% to 25% less than the unbundled rate.

What this means is that in order just to equal the standard service offer -- even before offering any savings to a commercial or small to medium size industrial customer -- a CRES provider will have to deliver generation that is 19% to 25% less than CG&E did in its last rate case. If the standard service offer rates included the same cost components as those of a CRES provider, and the customers could pay 19% to 25% less than they are paying now, the OMG would consider that to be competition and would not be protesting. That is not how the RSP works, though, for the standard service offer is

[51] The RTC do not contain stranded generation costs, but regulatory items such as FASB 109 payments TR Vol. IV. 122
[52] OMG Exhibit 13, Attachment FL-3

being supplemented by all the generation costs which have been crammed into the POLR plus a possible cross-subsidy from the mandatory RSC charge. Thus, if the RSP is approved, the commercial and small and medium size customers will experience an increase over what they are paying now by the amount of the POLR, which they can avoid only if they find a CRES provider that can deliver power at the artificially low match price.

Given how "g" was calculated, it is hard to imagine how one could argue that it is a "market price" for power. CG&E witness Rose tried to put the best face on it—however, not even witness Rose could call this price "market based"—by noting that when he looked at the range of prices OMG members charged Ohio customers in the period January 1, 2003 – through April 2004 the prices were similar to "g."[53] There are two problems with that analysis as pointed out in Mr. Lacey's supplemental testimony.[54] First, the prices in the Joint Exhibit were 2003 prices for 2003 – 2004 deliveries -- they are past and what is past is not prologue. The period in question here is 2005 – 2008. CG&E, as part of its application, has indicated that it will have to pour millions of dollars into environmental compliance costs that are required now. That investment must be included in the generation price and made part of the price to compare. Even if the prices did match for 2003-2004 (which they don't), that would only prove to be coincidence rather than a correlation, in much the same way that a stopped clock has the correct time twice a day.

Second, the prices listed in the Joint Exhibit are for all classes of customers for delivery in other service areas. It is simply not a good comparison of what a price to

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[53] OMG \ CG&E Joint Exhibit
[54] OMG Exhibit 13, p. 9

Cinergy would be for any particular class. Finally, Mr. Rose seeks to show that the "g," which clearly is not the product of actual market activity, represents a market price because the CMO MBSSO price could be lower than the RSP standard service offer.

The CMO MBSSO is a projection based on survey data. If CG&E had stopped there, it may have been acceptable, had it been adjusted by a collection of adders and then priced by load factor instead of tariff rate. The fact that the CMO MBSSO, which is not based on actual comparable sales, may fall below the "little g," which is not based on actual sales, provides no insight as to what actual sales for the forward period 2005 - 2008 looks like. Further, Mr. Rose had to "...chop down the CMO MBSSO retail adders to force the CMO price underneath the ERRSP MBSSO rate."[55]

If the RSP is approved as per the Stipulation, CG&E will be permitted to divert part of its environmental compliance costs and homeland security expenses to protect generation and reserve margin costs from the price to compare. In 2005, for the DS and DP rate groups (which cover all the commercial and industrial customers, except for the very largest who are on the TS rate), the "price to compare" will be lower than the incentized shopping credit for all but DP tariff customers with a load curve under 35%. (See chart FL-4 part of OMG Exhibit 13 which is attached to this brief as Attachment 1). Even with fuel increases of the size estimated by Mr. Steffens in years 2006 – 2008, the "price to compare" for most commercial and industrial customers will be below the incentive rate and well below an unincentized rate. (See Attachment 1)

CG&E witness Green presented a chart which tracks shopping.[56] The Green chart shows that 20% shopping levels were reach a couple of years ago. Under the

[55] Ibid p. 9
[56] CG&E Exhibit 4, Attachment WLG -1

transition stipulation, once the 20% limit was reached the shopping credits were reduced. The unincentized rates have produced virtually no shopping leading Witness Lacey to opine that the market clearing price today for commercial and industrial customers is somewhere between the incentive and the regular shopping price. As shown in Mr. Lacey's Attachment 1, the "price to compare" for most of the commercial and industrial class customers in the DP and DS schedules - even with fuel increases - by 2008 will still be below the unincentized shopping credits. The conclusion that Mr. Lacey draws, and one that any objective analysis at this time would draw, is that shopping will decline under the RSP because of the decrease in the price to compare, even though the cost to the customers on standard service for generation will increase. This is at odds with the Commission's requirement; thus, the RSP must be amended.

X. Issue No. 7: Section 4928.14, Revised Code requires a competitive bid out and a market based standard offer. CG&E's two proposed programs, the CMO and the RSP, both fail to meet the statutory requirement.

The General Assembly, as part of the Senate Bill 3 restructuring, set a market development period with a maximum of five years, during which both customers and electric utilities were supposed to make the transition from monopoly-supplied generation at cost of service rates to market based supplies and pricing. By the end of the market development period, generation was to be sold or transferred to a non-utility generation company. At the end of the market development period, it was hoped that many customers would have learned how to shop for alternative electricity supply and possibly even have found a CRES provider. For those customers who did not or could not find a CRES provider, Senate Bill 3 mandates that electric utilities provide two options in addition to the right of customers to contract with their own CRES supplier.

First, Section 4928.14(A), Revised Code, mandates that an electric utility provide a "market based standard service offer" (the "MBSSO") that includes all components of electric service including generation. Second, Section 4928.14(B), Revised Code mandates that an electric utility also provide an option to purchase competitive retail electric service, the generation price of which is to be determined thorough a competitive bid-out procedure. If the competitive bid price is approved by the Commission, the competitive bid price may be used as the MBSSO by the electric utility. Section 4928.14(B), Revised Code. The Commission, in Case No. 01-2164-EL-ORD, has issued rules on the competitive bid-out procedure called for by Section 4928-14(B), Revised Code. These rules state that the competitive bid-out will be conducted by a third party auctioneer to ensure fairness and to bring expertise as to the finer points of the auction. The rules also call for at least two bids, one for residential and small commercial customers and the other for large commercial and industrial customers. The rules call for the competitive bid-out to be for a fixed price. Finally, and most importantly, the Commission's competitive bid-out rules call for all retail customers who have not contracted with a CRES provider at the end of the market development period to be served by the competitive bid-out. Customers who drop their CRES provider or are in between CRES providers will be served by the MBSSO.

The General Assembly provided but one exception to the procedure for establishing the competitive bid process (the "CBP") under Section 4928.14(B), Revised Code. Specifically, the Commission may determine that the CBP is not required if other means are available in the market to establish generally the same option and a reasonable means for customer participation is developed. Id.

CG&E's RSP presents the Commission with the Hobson's choice between two unlawful alternative methodologies to comply with the dictates of the statute. CG&E first re-advocates its filings in Cases Nos. 03-93-EL-ATA, 03-2079-EL-AAM, 03-2081-EL-AAM, and 03-2080-EL-AAM that propose a Competitive Market Option ("CMO") methodology that allegedly establishes market based rates. RSP at pgs. 10-11. Second, CG&E offers the Commission an Electric Reliability and Rate Stabilization Plan (the "ERRSP") that allegedly results in a MBSSO in compliance with Section 4928.14, Revised Code. Id.

Both of the options presented by CG&E clearly violate the plain language of the Section 4928.14, Revised Code and are unlawful. The Commission is a creature of statute and does not have the authority to amend or ignore the requirements imposed upon it by the Ohio legislature. *Time Warner AxS v. Pub. Util. Comm.* (1996), 75 Ohio St.3d 229, 234, 661 N.E.2d 1097. The Commission has no authority to approve a plan that violates Ohio law; therefore, CG&E's RSP for any period after December 31, 2005 should be denied.

A. CG&E's Competitive Market Option violates both subsections of Section 4928.14(A) and (B), Revised Code.

CG&E's CMO purports to contain both an MBSSO and a CBP; however its versions of both fall far short of the plain language of the statute. The language of the statute is clear and unambiguous.

> After its market development period, an electric distribution utility in this state shall provide consumers, on a comparable and nondiscriminatory basis within its certified territory, a market-based standard service offer . . . ." R.C. §4928.14(A)(emphasis added).

Despite this statutory mandate, CG&E proposes a MBSSO that is "fashioned" by combining a mix of vague and ill-defined fixed and variable components. RSP at p.13. The basis of the CMO is the use of spot (as opposed to forward) market survey data. If evidence was presented that the surveys, i.e., MegaWatt Daily (which just surveys on peak sales) and ICE (which surveys both off and on peak sales) accurately reflect the market transactions and were representative, that would be a suitable basis to set a market based rate. However, the problem with the CMO approach is what happens after the survey data is collected. First, the prices to compare are not based on the current tariff models. CG&E uses a new set of price models based on load curves. The plan did not provide how customers and CRES providers would find the information needed to determine what is the price to compare, nor did the application demonstrate how the load curves used to price the CMO MBSSO would be "comparable" with the market.[57]

Even more controversial is CG&E's proposal that would allow it to selectively discount some customers' price to compare, but not others. As CPS witness Smith pointed out, when two like customers are now receiving unlike standard offers, it is discriminatory. Further, the selective discounting could be aimed just at those customers receiving competitive bids.[58] At a minimum, the net result would be discriminatory and, at worst, both discriminatory and anti-competitive.[59] In sum, what is being proposed by CG&E, so long as it can be selectively managed by CG&E, is not a market-based standard service offer as specified by the General Assembly. As such, the MBSSO proposed by CG&E should be rejected.

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[57] OMG Exhibit 15, Direct prepared testimony of Michael Smith, p. 5

[58] Ibid

[59] Note that Commission staff found the nature of CG&E's original MBSSO proposal to be intrinsically anti-competitive. See the March 14, 2003 Staff Comments, pp. 1-3.

In addition, CG&E's CMO sets forth a CBP allegedly designed to provide "non-residential end-use consumers" with a "competitive offering by a competitive retail electric service provider." Id. Despite this bold assertion, the CBP proposed by CG&E falls short of the unambiguous requirements of Section 4928.14(B), Revised Code. The General Assembly clearly requires that, in addition to an MBSSO, an electric utility "shall offer customers within its certified territory an option to purchase competitive retail electric service the price of which is determined through a competitive bidding process." Section 4928.14(B), Revised Code. The specific details of the CBP were set forth by the Commission in Case No. 01-2164-EL-ORD.

The Commission's rules governing the CBP are clearly articulated. CG&E has failed to demonstrate that its CMO satisfies those requirements even though months have gone by between the Commission's ruling in the CBP rules proceeding and the case at bar. From the OMG and CPS perspective, the greatest failure of the CBP is its failure to follow the rules that require all customers that have not shopped by the end of the market development period to receive standard offer generation service by virtue of a competitive bid out process. In the CMO version of the CBP, the winning bidder receives no customers, only the potential liability to serve all customers in a class at a fixed price. As Witness Smith makes clear in his testimony, there is no advantage to bidding in the CBP. This is because whether it wins or loses the CBP, a supplier will still have to contract individually with the customers. Thus, the CMO is a competitive bidding process designed to attract no bids.

B. CG&E's RSP presents an Electric Reliability and Rate Stabilization Plan that violates Section 4928.14(A) and (B), Revised Code.

Similarly, CG&E's RSP violates the plain language of Section 4928.14, Revised Code, and is consequently unlawful and should be denied. In the RSP, CG&E offers an alternative to the CMO that allegedly "represents a comprehensive solution to the issues and concerns of the Commission . . . and provides consumers with an extended transition to a fully competitive retail electric market after the market development period." RSP at p.15. Notwithstanding CG&E's unsupportable claims about the merits of its proposed RSP version of the market based standard service offer ("ERRSP"), CG&E's proposal violates the mandates of the General Assembly.

As a preliminary matter, CG&E's ERRSP proposes a new type of rate that has no basis in law. Specifically, CG&E insinuates that the ERRSP will provide some sort of less than market-based interim rate during transition to "a fully competitive retail electric market . . . ." Id. Section 4928.14, Revised Code is unequivocal, however, that an electric utility "shall provide consumers . . . a market-based standard service offer . . . ." Section 4928.14(A), Revised Code (emphasis added). Clearly the legislature did not create nor did it differentiate between "fully competitive" retail rates, presumably the MBSSO, and something less than a market-based rate. Indeed, nowhere in the statute is an electric utility permitted to create its own interim rate that is anything other than a MBSSO. Consequently, CG&E is fabricating a new type of interim rate that has no authorization or justification in law.

The CG&E ERRSP contains other more specific flaws that are fatal in light of Section 4928.14, Revised Code. Primarily, the ERRSP attempts to create the MBSSO using a methodology, explained on page 31 of this brief, that has no basis in a competitive electricity market. Specifically, the ERRSP has an artificial generation price to compare "g" which is not based on actual sales or agreements between willing buyers and willing sellers. Further, as described above, real generation costs such as reserve margin, environmental compliance costs and security for the power plants are diverted so as to be eliminated from the price compare.

The CG&E ERRSP's proposed methodology to create a MBSSO has no basis in the statute that clearly defines the parameters and content of a MBSSO. There are only two ways to lawfully create the required market rate for electricity under Section 4928.14, Revised Code. First, the rate can be a "market-based standard service offer" that is then filed with the Commission under Section 4909.18, Revised Code. Section 4928.14(A), Revised Code. Second, the competitive bid option that all electric utilities are required to offer, may be used as the MBSSO if the Commission so approves. Section 4928.14(B), Revised Code. The CG&E ERRSP complies with neither of the methods to establish the MBSSO. Furthermore, CG&E's ERRSP departs substantially from a market-based rate when it requests the addition of a sizable and potentially ever increasing POLR charge as a form of cost recovery.

Turning from the market based standard service offer to CBP, the CG&E RSP fails to abide by its statutory obligation to "offer customers within its certified territory an option to purchase competitive retail electric service the price of which is determined through a competitive bidding process." Section 4928.14(B), Revised Code. CG&E ignores the competitive bidding requirement as specified in the statute and the Commission's regulations. Instead, paragraph 13 of the Stipulation provides that the Commission may use a competitive bidding process to test the RSP rates, but only against the price to the 25% of the customers who are not forced to purchase the rate stabilization program. On its face, this proposal is defective. First, it does not result in a competitive bid, for the results of the test are only discussions – not bids. Second, any comparison worth having would compare the cost to all customers in the service area; that includes the 75% who are forced to pay the RSC charges as well those who are not. The statute is unequivocal. The competitive bidding process is a mandatory obligation of the electric utility, not the Commission, and its purpose is to offer customers an option to purchase competitively bid electric service, not to "test" the sufficiency of other arrangements.

The only lawful way that CG&E may avoid the mandatory competitive bidding requirements is if the Commission determines "that a competitive bidding process is not required, <u>if other means to accomplish generally the same option for customers is readily available in the market and a reasonable means for customer participation is developed</u>." Section 4928.14(B), Revised Code (emphasis added). Today, there is little marketing activity in CG&E's service area, and no one has suggested that there are so many market based options open today in CG&E's service territory that a competitive bid would simply be duplicative to what is already available in the market. Absent that kind of proof, a bid is necessary to give retail customers options and to test the mettle of the RSP.

The Commission, in an almost identical proceeding regarding the proposed Rate Stabilization Plan for the FirstEnergy Companies, ruled that prior to any RSP going into effect, a competitive solicitation for firm commitments to provide full requirements standard offer generation service should take place. If the competitive solicitation provides "better benefits" for customers, FirstEnergy's RSP will not be implemented, and the customers will enjoy the "better benefits" of the competitive solicitation. This precedent should be followed in the matter at bar.

XI. Conclusion and Recommendations

As detailed in the foregoing sections, both the Competitive Market Option filed last year, and the RSP filed this year as amended by the Stipulation violate Section 4928.14 (B), Revised Code because both fail to contain a competitive bid option in accordance with the Commission's rules. Both the CMO and the RSP present standard offers which are not "market based" or "comparable" and actively discriminate in violation of Section 4928.14 (A), Revised Code and Section 4928.02 (G), Revised Code. The RSP violates the Commission's entry requiring that all proposed rate stabilization plans promote market development as well as provide equitable compensation for the distribution utility. The proposed RSP would artificially reduce the "price to compare" to a level that will reduce, if not eliminate, the ability of most commercial and industrial customers to shop. Finally, the RSP seeks an indefinite waiver for CG&E from the statutory requirement for separation of its non regulated generation assets and business from its regulated utility distribution assets and service. The statute, however, provides the Commission with no such authority after the market development period, nor if it did would the waiver be in the public's interest.

For the reasons set forth above, the Commission should take the following steps:

1. Reject the waiver request from the statutory dictates of Section 4928.17, and order CG&E to separate in accordance with its transition plan filed and approved in Case No. 99-1658-EL-ETP.

2. Convene a stakeholders' proceeding to design and plan for a competitive bid in accordance with the Commission rules on competitive bid, and retain a third party administrator to design and conduct the competitive process for 2005 for implementation in 2006.

3. If the commercial and industrial class are in fact at 20% on December 31, 2004[60], permit the RSP to go into effect for commercial and industrial customers for 2005 as per the Stipulation with three amendments: a) the RSC charge should be an election for everyone, not just 25% of the customers – and thus be bypassable; b) the cost elements in the variable component of the POLR charge should be moved to the generation component of the ERRSP – and thus be bypassable; and c) customers who do not sign up for the RSC and return to CG&E for service should pay the highest cost CG&E must pay for power – not the highest cost of any CG&E affiliate.

4. If, in 2005, the competitive solicitation process produces "better benefits" for retail customers than the RSP, then the RSP will end December 31, 2005, and the results of the competitive solicitation will be used to provide standard offer generation service to customers who have not made other arrangements and set the price thereof.

5. If the Commission does not grant the requested amendment to transfer the POLR variable costs to the generation component, then, for 2005, the Commercial and Industrial customers who are shopping now and remain

[60] The state of the record as of hearing was that the industrial was at 19.89% See TR. Vol. II at 133

on the shopping credit plan should be exempt from the variable POLR charges as well as the RSC.

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CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Initial Joint Brief of Constellation NewEnergy, Inc., Constellation Power Source, Inc., MidAmerican Energy Company, Strategic Energy LLC, and WPS Energy Services, Inc. was served either by email or regular U.S. mail, postage prepaid, this 22nd day of June, 2004.

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ATTACHMENT 1

Attachment FL-4

Shopping Credit Comparison

DS Tariff (250 kW customer)

Load Factor	Current Shopping Credit (2001-2005)	Incentivized Shopping Credit	ERRSP 2005 Price to Compare	ERRSP 2006 Price to Compare	ERRSP 2007 Price to Compare	ERRSP 2008 Price to Compare
	(Next 80%)	(First 20%)				
35%	4.25	4.81	4.38	4.39	4.39	4.40
50%	4.25	4.81	3.56	3.57	3.58	3.59
65%	4.25	4.81	3.09	3.10	3.11	3.12
80%	4.25	4.81	2.81	2.82	2.82	2.83

DP Tariff (1500 kW customer)

Load Factor	Current Shopping Credit (2001-2005)	Incentivized Shopping Credit	ERRSP 2005 Price to Compare	ERRSP 2006 Price to Compare	ERRSP 2007 Price to Compare	ERRSP 2008 Price to Compare
	(Next 80%)	(First 20%)				
35%	3.51	3.89	4.18	4.19	4.20	4.21
50%	3.51	3.89	3.47	3.48	3.49	3.49
65%	3.51	3.89	3.06	3.07	3.08	3.09
80%	3.51	3.89	2.80	2.81	2.81	2.82

* Assuming a 5% Annual Increase in the Fuel and Power Purchase Costs