Q: WOULD YOU STATE YOUR NAME AND BUSINESS ADDRESS?

A: My name is James M. Russell. My business address is 1300 S Evergreen Pk Dr SW, Olympia, Washington, 98504.

Q: BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A: I am employed by the Washington Utilities and Transportation Commission (Commission) as a Policy Research Specialist.

Q: HAVE YOU PREVIOUSLY PROVIDED WRITTEN TESTIMONY IN THIS DOCKET?

A: Yes. I provided written testimony on July 21, 2000 regarding issues related to Northwest Natural Gas Company's (Company) revenue requirement.

Q: WHAT IS THE PURPOSE OF THIS WRITTEN TESTIMONY?

A: I will provide testimony supporting Staff's proposal on rate spread, rate design, and on the allocation of upstream gas supply costs.

Q: DO YOU PROVIDE ANY EXHIBITS WITH THIS TESTIMONY?

A: Yes, I have prepared Exhibit ___ (JMR-5), which I will describe later in this testimony.

GAS COST ALLOCATION

Q: WOULD YOU PLEASE BRIEFLY DISCUSS YOUR RECOMMENDATION REGARDING THE ALLOCATION OF UPSTREAM GAS SUPPLY COSTS?

The Commission should reject the Company's proposed simplistic peak day allocation of upstream gas supply "demand" costs because it ignores the fact that these costs are incurred to serve annual and incremental winter volumes, not just a single peak day's volume. The Commission should adopt a base-intermediate-peak methodology for the allocation of these costs consistent with prior cost of service decisions.

Q: WOULD YOU PLEASE EXPLAIN WHAT YOU MEAN BY THE TERM "UPSTREAM GAS SUPPLY COSTS"?

A: Upstream gas supply costs, or simply "gas costs," are costs incurred by the Company to secure and transport natural gas supplies to its system. The term "upstream" refers to the fact that the Company does not own the large interstate pipeline system "upstream" of its various city gates (the connection point with the interstate pipelines), but rather makes fixed monthly payments to third parties for the right to use these pipelines to transport supplies to its system. Upstream gas supply costs fall into two categories. First, the Company purchases natural gas supplies in the open market from a diverse group of Canadian and domestic suppliers. These supply costs are referred to as "commodity costs." The Company's commodity costs vary directly with usage (sales). These supplies are then transported to the Company's system, or placed in storage facilities, through interstate pipelines. The payments to reserve pipeline and storage capacity from third parties are referred to as "demand costs." The Company pays fixed costs for the reservation of pipeline and storage capacity whether or not they are used.

Q: HOW DID COMPANY WITNESS MR. FERGUSON ALLOCATE COMMODITY AND DEMAND GAS COSTS IN HIS COST OF SERVICE STUDY?

A: Mr. Ferguson allocated commodity costs to the various sales schedules based on annual sales volumes. He allocated all upstream pipeline and storage demand costs based on a single peak day's sales volumes.

Q: DO YOU AGREE WITH MR. FERGUSON'S ALLOCATION OF COMMODITY AND DEMAND GAS COSTS.

A: I agree with the allocation of commodity costs, but do not agree with his allocation of demand costs.

Q: HAS THE COMMISSION ADDRESSED THE ALLOCATION OF GAS COSTS IN PRIOR PROCEEDINGS?

A: Yes, in several prior proceedings; the most current case being Docket No. UG-940814 involving Washington Natural Gas Company. In that case, the Commission approved the allocation of gas supply commodity costs on the basis of annual sales volumes and the allocation of gas supply demand costs on a base-intermediate-peak methodology.

Q: WOULD YOU PLEASE DISCUSS HOW YOU PROPOSE TO ALLOCATE GAS DEMAND COSTS?

A: I propose that the Commission adopt a base-intermediate-peak methodology consistent with prior decisions regarding the allocation of gas supply demand costs. Page 3 of Exhibit ___ (JMR-5) illustrates Staff's proposed base-intermediate-peak allocation of gas supply demand costs of $5,903,644 (line 14). Lines 1 through 13 show the detail of the various demand costs (pipeline and storage capacity costs) incurred by the Company. TF-1, TF-2, Canadian Demand Charges, K.B. Pipeline, and Temporary Capacity are all fixed costs incurred by the Company to transport supplies either to its system, or in and out of storage. Capacity Release Credits (line 9) are monies received by the Company for releasing pipeline capacity to third parties.

I have split TF-1 Demand Charge (lines 1 and 2), Canadian Demand Charge (lines 4 and 5), and Temporary Capacity costs (lines 7 and 8) into two portions. One portion represents the costs associated with serving peak sales requirement. The other portion includes the costs associated with serving annual sales requirements. These costs are split based on the peak and average percentages shown on lines 19 and 20. The "Peak" portion of these demand costs are allocated based upon each schedule's contribution to the Company's peak day volume, as determined by Dr. Mariam. The

"Avg" (average) portion of these demand costs are allocated based upon each schedules' contribution to annual volumes. This allocation of upstream pipeline demand costs mirrors the "peak and average" allocation of the Company's distribution mains.

TF-2 Demand Charge (line 2) and K.B. Pipeline (line 6) are costs incurred to move gas supplies into, or out of, storage, and accordingly have been allocated based on incremental winter volumes (SEASONAL-INCR allocator).

SGS-2 Demand and Capacity costs (lines 10 and 11) are fixed costs the Company incurs to reserve storage capacity at Jackson Prairie. These costs are allocated based on incremental winter volumes. LS-1 Demand and Capacity costs (lines 12 and 13) are fixed costs incurred by the Company to reserve capacity at a needle peaking storage facility located in Plymouth, Washington. These costs are allocated based on firm peak day volumes.

Line 14 shows the total gas supply demand costs allocated to each schedule. These are the total gas supply demand costs reflected in Dr. Mariam's cost of service.

<u>RATE SPREAD</u>

Q TURNING TO RATE SPREAD, WOULD YOU PLEASE BRIEFLY SUMMARIZE YOUR RATE SPREAD PROPOSAL?

A: Based on Dr. Mariam's cost of service and the Staff's proposed total additional revenue requirement of $3,220,900, the following is a summary of the results of my rate spread proposal (three year totals):

	Amount	Percent Increase
1.5% Late Fee, $3.00 Min. (Co. Proposal)	$27,844	
Schedule 1 - General Sales	$10,874	14.44%
Schedule 2 - Residential	972,481	12.56%
Schedule 3 - Comm. and Ind.	263,793	3.00%
Schedule 4 - Lg. Firm Service	99,758	6.28%
Schedule11 - Seasonal Swing	1,898	5.00%
Schedule 21 - Firm Hi Load Factor	78,147	3.00%
Schedule 22 - Inter. Dual Fuel	1,223	3.00%
Schedule 23 - Hi Priority Inter.	30,179	6.28%
Schedule 24 - Res. - All Gas	1,340,994	12.56%
Schedule 27 - Dry Out Service	90,490	15.00%
Schedule 55 - Long Term Incentive	261,290	13.81%
Schedule 90 - Firm Transportation	41,940	11.30%
Total/Average	$3,220,911	8.99%

Q: HOW DID YOU DETERMINE YOUR RATE SPREAD?

A: Page 1 of Exhibit ___ (JMR-5) details my rate spread proposal. Given the magnitude of the increase facing the Company's Washington customers, each class should support a portion of the increase. Therefore, I propose that no one schedule bear a total increase greater than 15%, nor lower than 3%, over the three year period. Given that criteria, with the exception of Schedule 11 - Seasonal Swing Service, I then applied a percentage increase within this band in order to move each schedule's rate of return (line 15) and revenue to cost ratio (line 19) toward unity. The further away a schedule was from unity (higher or lower than unity), the higher or lower percentage increase I applied in order to move each rate schedule toward unity.

Q: WHAT DO YOU PROPOSE WITH SCHEDULE 11 - SEASONAL SWING SERVICE?

A: I have applied a smaller percent increase to Schedule 11 than the current rate of return and revenue to cost ratio would suggest, in order to keep the rates in line with Schedules 4 and 21. Schedule 11 is designed to provide off-peak customers a cost savings if they use gas during the summer months. If Schedule 11 were increased too much in relation to Schedules 4 and 21, it would become uneconomic. Therefore, I have proposed only a 5% increase to Schedule 11. Since there is very little revenue generated on Schedule 11, this departure in rate spread has virtually no revenue impact on any other schedule.

Q: IF THE COMMISSION ADOPTS A LARGER REVENUE REQUIREMENT OR SHORTER PHASE IN PERIOD, WHAT WOULD YOUR RECOMMENDATION WITH REGARD TO RATE SPREAD BE?

A: I would recommend that the Commission determine rate spread in a manner that I have suggested above, however, the lower end of the "percent increase" band (3%) be increased until the additional annual revenue requirement is satisfied.

RATE DESIGN

Q: PLEASE DISCUSS YOUR RATE DESIGN PROPOSAL.

A: My rate design proposal is illustrated on page 2 of Exhibit ___ (JMR-5). My proposal is simple and straight forward. I propose that each rate schedule's rate spread percentage increase shown on page 1, line 23, be applied equally to each schedule's rate component.

Column (b) of page 2 shows the Company's December 1, 1999 permanent rates. Column (c) shows the applicable three year total percent increase. Column (d) shows the total rate change after the three year phase in is complete. Column (f) shows the rate changes in order to generate the first year's phase in amount of $1,220,900. Column (h) shows the rate changes required in years two and three to generate an additional $1,000,000 in each of those subsequent years.

Q: DO YOU HAVE ANY OTHER RATE DESIGN PROPOSALS?

A: Yes. Currently, for Purchased Gas Adjustment (PGA) purposes, the Company's interruptible Schedules 22 and 23 rates are assumed to have a demand increment of $.01279 per therm embedded in them (Exhibit ___ (JMR-5), page 3, line 18). I propose that the PGA demand increments be re-balanced to reflect the results of the demand gas cost allocation so that interruptible Schedules 22 and 23 have a higher average demand increment of $.07014 per therm embedded in them. Correspondingly, for PGA purposes, firm schedules' demand cost increment must be reduced from

$.10621 per therm to $.10487 per therm ($.00134 reduction). The calculation of the interruptible demand increment of $.07014 per therm and firm demand reduction of $.00134 per therm is shown at the bottom of page 3, Exhibit ___ (JMR-5).

Q: DOES THAT CONCLUDE YOUR TESTIMONY?

A: Yes.