Utilities Customer Advisory Group
Minutes for the Meeting on
March 10, 2021
3:00 p.m.
Zoom Webinar

Committee Members Present
Eugene Suttmiller, Chairman
Paul Royalty, Committee Member
Robert Snyder, Committee Member

Others
Jason Mumm, Stantec
Grant Rabon, Stantec
Cassie McClure, McClure Publication
William Little, LCU Board Chairman

City Staff Present
Tanya Cereceres, Administrative Assistant
Jose Provencio, Business Services Administrator
Domonique Rodriguez, Rate Econ. Analyst Mgr.
Mario Puentes, Gas Business Analyst
Delilah Walsh, Utilities Director
Alma Ruiz, Office Manager Senior
Melissa Miranda, Office Assistant Senior
Lisa Valleroy-Djang, Office Assistant Senior

Chair Suttmiller called the regular meeting to order at approximately 3:01 p.m.

Chair Suttmiller: Okay, we're set to go. First off I want to welcome everybody here. Thank you for appearing. I'm calling the meeting to order. I'm calling Utility Customer Advisory meeting to order. First of all, I need to recite some guidance from the State of New Mexico. Considering that we are operating remotely, we need to remember that we need to announce the names of those members of the public body that are participating. As those members speak they must identify themselves whenever they do speak and members of the public are afforded remote access through our web link. If the audio or the video of this meeting *(inaudible)*. All votes will be by roll call. I do know that we have quorum just to begin, ask who is the quorum. I Eugene Suttmiller am here.

Royalty: Paul Royalty is here.

Snyder: Bob Snyder is here.

Chair Suttmiller: Okay, who else is here? I've got a Jason Mumm and Paul Royalty. Mr. Royalty?

Royalty: Yes, I'm here.

Chair Suttmiller: Okay, thank you very much. Did you ever hear how we are to conduct the meeting Mr. Royalty?

Royalty: Yes, I did.

1. <u>Conflict of Interest:</u>

Chair Suttmiller: I will go to the next one. I need to ask if any members of the committee or any member of the City staff have any known Conflict of Interest with any item on the agenda? Please respond with your name and your answer.

There were none.

2. <u>Acceptance of Agenda:</u>

Chair Suttmiller: I want to move next to the Acceptance of the Agenda. Do I have a motion to accept the agenda as it is or if you want to make a change to it please say so?

Snyder: I move to accept the agenda.

Royalty: And I second that.

Chair Suttmiller: Okay, and call for vote and again we need to hear the names. All in favor.

The Agenda was Accepted Unanimously 3-0.

3. <u>Approval of Minutes:</u>

a. Regular Meeting Minutes of February 24, 2021

Chair Suttmiller: I now need to get approval of the acceptance of the minutes from the last meeting. Do I hear a motion?

Royalty: I'll make that motion.

Chair Suttmiller: Okay. Do I hear a second?

Snyder: I'll second

The Minutes were Approved Unanimously 3-0.

4. <u>Approval of New Vice-Chair:</u>

Chair Suttmiller: We have next approval of the new Vice-Chair. I have to ask you who's the new Vice-Chair that we're approving. I haven't heard anything about that.

Royalty: The last meeting we had, I said I would serve as the new Vice-Chair.

Chair Suttmiller: Okay. Now do I hear a motion to accept Mr. Paul Royalty Vice-Chair.

Snyder: I so move.

Chair Suttmiller: I second that motion. We now have to do a vote so that all three members again.

The Paul Royalty as Vice-Chair Approved Unanimously 3-0.

5. <u>Public Participation:</u>

Chair Suttmiller: Now we come to Public Participation. I have been informed that we do have somebody who wishes to join us. And if you can make that happen Tanya, I'd appreciate it.

Shervanick: Good afternoon. Thank you for the opportunity to address the Utility Customer Advisory Group. My name is Gregory Shervanick S-H-E-R-V-A-N-I-C-K for the record. I must read a disclaimer now. I am not or have never been a member of this group, a member of the City staff or any other utility. The reason I am addressing you today is that the gas utility is the last of the services to be assessed for an increase. I have personally listened to, observed, and participated in all the other utility rate increases presented by this group. I have engaged members of this group past and present at public presentations and members of the Las Cruces Utility staff about the other utility rate increases. I hope that you will include in your analysis of the Gas Utility Rate increase the documents and budget proposal that will be presented at the Utility Board work session tomorrow, March 11, 2021. I am encouraging that this information be included along with the Stantec presentation today, as this group finds facts to recommend to both the Utility Board and the City Council for a rate increase to the gas. Positive transparency can only increase public confidence for the 38,000 ratepayers that will receive this rate increase. I thank you very much for this time to express my opinion on this matter.

Chair Suttmiller: Mr. Shervanick. I want to thank you for coming and talking to us. We appreciate any input from ratepayers. I think I remember you quite well from previous ones. You're more than welcome to sit in the meeting and hear the presentation from Stantec. That's up to you if you want to put the time in. You're more than welcome to stay on.

Shervanick: Thank you Mr. Suttmiller.

6. <u>Gas Rate Review:</u>

Chair Suttmiller: Let's do the Gas Rate Review.

Rodriguez: Chairman. My name is Dominique Rodriguez. I'm the Rate and Economic Analysis Manager. We have today with us Jason Mumm, who has been the project manager for our rates reviews. We also have Grant Rabon, who is the subconsultant that did our Gas Rate Review. He will be providing the presentation today for the gas rate review.

Mumm: Grant. Do you want to share your screen?

Rabon: Yes, I'd be happy to.

Mumm: While you're doing that, I'll just make a few introductory comments, and then once you're ready to go I'll turn it on. Just wanted to reintroduce ourselves. Dominique just give our names. I've appeared before this group, now this will be my fourth time. We started a few years ago actually working on the Water case first, we progressed to the Wastewater Rate Case and then the Solid

Waste Rate Case. During this pandemic filled year, we have been working with staff to complete this Gas Case. You're about to see the results put in front of you today.

What we've got today is a summary of three things that are the core elements of any kind of rate study. These were the same core elements that we talked about with those water, wastewater and solid waste cases too. It starts with Revenue Requirements; how much money does the Utility need to meet all of its financial obligations in a given year. Then it progresses through a cost allocation process to determine how all of those costs are picked up in the system, and by whom, and then to rate design. Grant Rabon is with a firm called NewGen Strategies. He is a subcontractor to us on this project. He also presented to you on the Solid Waste Case a year ago or so. He's here again today to review these numbers on the Gas Case with you. I'm going to step aside and I'm going to have Grant step up to the microphone. He'll take you through what we have. We look forward to your questions. Thank you very much. Grant, all yours.

Rabon: Thanks so much, Jason. Thanks very much to this group for making time to allow me to present this information. I should be sharing my screen at this time, you should be seeing a cover slide. Thanks again for your time. Yes, as Jason alluded to, we have a presentation to provide to you. If at any point along the presentation you have a question or want to dive into an issue deeper, please feel free to stop me and let me know if you have a question or want to talk about an issue as we're going through this. The goal is to review the utility rate setting process that Jason just referred to, look at the Revenue Requirement that was developed for the gas utility's continued operation, then look at the Cost of Service based off of the cost of providing services to different classes of customers with the gas utility. Then look at some proposed rates and then some benchmarking.

This overview of the rate setting process is essentially what Jason was just describing verbally, we were looking at the Revenue Requirements, then developing a Cost of Service for each of the various customer classes, and then looking at how to design rates to both recover those costs equitably but also achieve the goals of the Utility. This first step in this process is developing the Revenue Requirement. This Revenue Requirement was developed primarily based off of the fiscal year 2020 actual results, as the test year starting point. We did make various known and measurable adjustments to the 2020 actuals. The most notable and meaningful being to update the salary and salary related costs that the Utility actually incurred in 2020 to be updated and reflective of the fiscal year 2021 budget for those expenses as we know the increase they will occur in that category of costs. We also annualized a level of vehicle and equipment replacement that will be sustainable to the Utility over the long term. We provided for a level of cash funding for capital projects in this Revenue Requirement. We developed an estimated debt service that includes not only the existing issues, but also one new proposed issue to pay for some capital spending, which we will go over here in a slide in just a minute. We

added the addition of possible funding for decarbonization program, and then we made some small, much smaller adjustments for miscellaneous items, for example, just normalizing the cost of engineering services that is incurred in Shared Services to be representative of what a more expected typical year for that cost element would be.

It's important to note that at least for the first portion of this presentation, the Revenue Requirement numbers we're going to be looking at exclude the cost of the gas commodity itself. The cost of the actual gas that gets sold is able to be passed through to customers through a separate line item on the bill. When we get to the end where we're looking at bill impacts, we've included that cost so that you can see what the total bill will look like. For the first part of this presentation it's important to note that you're looking at these numbers that is not including the actual cost of the gas, which is a considerable portion of the overall cost to the Utility.

Looking at the overall Revenue Requirement, I'm going to kind of walk through line by line these categories of costs, and then we will dive into them individually in a little more detail in the next slides. Starting at the top line of the cash operating maintenance expenses. Here again, in addition to not including the gas commodity as I just said, these are strictly the cash expenses of the Utility, so for example, it does not include depreciation or amortization because those would be noncash expenses and so they're not included in this development of the Revenue Requirement, because this Revenue Requirement was developed on the cash basis.

The next line item, vehicle equipment and replacement. You'll see in our test year we have just over $900,000.00 per year identified in necessary investment in vehicles and equipment on an annual basis going forward. The development of that number we'll get to in a future slide but that's what that represents. We then have a $1 million per year identified as cash from rates to pay for capital projects. Here again, we are also going to have a slide that talks in more detail about the capital program, not just the cash funded portion, but the overall capital program as well. Then we have represented in the test year, the annual debt service. Remember that in the test year we have added what amounts to almost a million dollars per year in principal and interest payments on a new proposed debt issue that would help fund some of the capital plan that we'll be looking at. Then for the purposes of developing this Revenue Requirement, we have reversed out or subtracted out the debt service specifically tied to existing series 2018 revenue bonds. Those debt service payments have a funding source external to the rates that are being set as part of this process. What we wanted to represent and show the total debt service, we also want to recognize that there's a portion of that debt service that is not expected to be funded directly from rates, and so we've showed it as a negative deduct from the Revenue Requirement here.

Next, we have an estimate of uncollectible expense. When you add all that up you have the total Revenue Requirement or costs for the Utility, not all of which

need to be recovered from rates. There are some other non-rate related revenues that pay for a portion of that overall Revenue Requirement, and those are reflected there as that negative $1.2 million number on the test year. This is composed of miscellaneous revenues connect, disconnect fees, late fees, penalty fees, you know other miscellaneous fees the Utility might charge as part of providing service. It also includes the revenue associated with a wheeling contract, where the Utility is moving gas on behalf of another entity, and the payments that are made as part of that program are also reflected there. Those are all things that reduce the amount of revenue that needs to be charged to customers through these rates we're looking at.

If you total all of that up it shows that you have roughly $13 billion per year that needs to be recovered from the rates we're looking at. The forecasted rate revenues under current existing rates, here again not including the gas commodity, so we want to be clear that we're not including the expense and we're also not including the revenue tied to the gas commodity, that would be roughly $10.7 million. There's a $2.4 million shortfall that needs to be addressed through these rates.

Digging into this a little bit to each of those different categories. This slide is showing you some recent history with regard to operating costs. Here again, this is, your cash operating costs were not included in this as depreciation and also just for reference it doesn't include debt service. It also does not include the cost of the gas commodity itself. With those pieces recognized as not being included here, it kind of shows you the categories for the different operating expenses and how they've been changing in very recent history, and how that compares to what's in the test year. The biggest change in these buckets of costs that are shown here are related to personnel costs, and those are necessary to attract and retain qualified individuals to operate the Utility, there either needs to be a compensation to be able to operate the Utility in that fashion.

Chair Suttmiller: We're talking from what I can see almost a million dollars increase in personnel costs. I'd like to see that broken down somewhere.

Rabon: Sure. Yes.

Chair Suttmiller: Why it's jumped so much. I can understand that raises were authorized by the City Council but in that seems to be an awful lot. What has changed? How many new people are we hiring in that $1 million?

Rabon: The two things, not all of that increase is tied directly to personnel, although it is a large portion of that $1 million difference. There is a very detailed summary that lists out all the noted measurable changes to the line item expenses for all salaries that we can look at to kind of show the detail or the math behind that change in number. I'd asked staff as an opinion as to whether or not we attempt to pull that up and start looking at that at this juncture or what's the preference of the board or staff?

Chair Suttmiller: I can wait, I just want to make sure that we can get briefed on it before we leave here.

Rabon: Okay. Yes, absolutely. Let's make a note.

Walsh: Grant. Can I make a comment real quick? Thank you, Mr. Suttmiller. I want to remind you too that when we're looking at our FY19 and 20 actuals when it comes to personnel expense, remember we've had between 15 and 18 vacancies in the gas section alone.

Chair Suttmiller: That's the kind of answers I'm looking for.

Walsh: Yes.

Chair Suttmiller: Why it's jumping up like that.

Walsh: When we make the assumption for the test year, we're assuming we'll have those vacancies full. But in reality we've had between 15 and 18 in the gas section, so that'll be a big chunk of it.

Chair Suttmiller: This is actual spending I'm seeing in 2019, and 2020 as it gets projected for, well it says a test year which was 2020 wasn't it.

Rabon: The test year is developed based on 2020, but remember one of the significant adjustments we made to the actual 2020 results was to reflect the budget salary and salary related expenses for the test year.

Chair Suttmiller: Okay. I'd still like to go through those personnel things before we get out of here.

Rabon: Okay.

Chair Suttmiller: Thank you.

Rabon: Absolutely. Another element we were talking about in the summary list of items we were building up to the Revenue Requirement was vehicle and equipment purchases. This is just showing kind of here again recent history with regard to contributions towards vehicle and equipment purchases and the actual purchases themselves shown here at the bottom as negative numbers. You'll note that in recent years the level of funding going towards the equipment purchases has been declining. The Utility is actually getting behind on the schedule of replacement for the individual types of equipment that are out in the gas area. For example, if you assume that a certain type piece of equipment is going to last for 10 years, the assumption is that you need to be planning for the replacement of that piece of equipment at the end of its assumed useful life. We are currently in a situation where there are several pieces of equipment which are still in service beyond that estimate of useful

life. Now, it doesn't mean that they're going to come to a screeching halt tomorrow, but the longer that goes on the more issues the Utility will have with breakdowns and issues with providing service due to equipment failure. It's a good idea and a best practice to keep those replacements funded so those periodic replacements of pieces of equipment are able to be made and you don't have a declining service issue.

What is reflected in the test year is developed based upon a detailed listing of every piece of equipment and vehicle utilized by the Gas Utility. When it was acquired, what it would cost to replace it today, and when it should be replaced based on the assumed replacement schedule for the various types of equipment. Then based upon that development, we have developed an estimate of what would the annual spending had been in the last four years of the Utility in terms of replacements. Then the forecast of what replacements should be in the next three years in order for the Utility to get back on course for these replacements. The amount that's in the test year is a combination of both actual experience of a recent history, four years, and a projection over the next three years, and it's an average of those seven years in order to develop the amount that was identified for replacements. Go ahead.

Chair Suttmiller: Again, I thought we had this problem licked when we did the others where we made it very plain what we wanted. Across the board not to see these dips down from $826,000.00 to $636,000.00 to $212,000.00 and then back up to $923.000.00. That disturbs me a little bit. I thought we had that licked back when they were doing Solid Waste.

Rabon: Fair enough. Just to be 100% clear you know the planning and the level of funding that was identified for the equipment related to Solid Waste was addressed in the Solid Waste study. Those pieces of equipment don't, the bulk majority of those solid waste pieces of equipment are collection trucks that are driving around collecting garbage, they're not the piece of equipment that are in the Gas Utility being used to operate the Gas Utility.

Chair Suttmiller: I understand the difference.

Rabon: Okay.

Chair Suttmiller: I'm looking at 2018, it was $826,000.00 was the cost for replacement of vehicles. I'm pretty sure 2017 was pretty close to that. Then we dropped down again, and we stopped replacing vehicles on a schedule apparently, went way down in 2020. That shouldn't have happened. We had the money in the last rate increase to maintain the replacement and it hasn't happened. Now we're going to go back up to $923,000.00 in the test year and what are we saying for the next couple of years after the test year. Is it going to remain? We're looking at $100,000.00 increase because the Utility didn't replace what it should have during 2019 and 2020 is what I'm reading here.

Rabon: Yes, so it's a few things embedded in there. You're not wrong, but I just thought I'd make it a little more nuanced. You know the $923.000.00 that's in the test year is reflective of a level of funding that year in, year out prospectively should be sufficient to get the Utility to be able to make the replacements when they need to. Something that just looking at fiscal year 2018 and the test year individually and saying there's a $100,000.00 difference, well part of that is a couple of things. One is capital inflation, so the cost of the pieces of equipment, and the rolling stock has changed since 2018. That's a piece of it. Also embedded in this test year amount is an assumption that the City will begin to start procuring some pieces of equipment that are more ecofriendly. Of the various pieces of equipment in that asset list, there were 11 trucks that are identified as being ones that could be replaced instead of with traditional fuels, with an alternative more environmentally friendly fuel source. Those cost more. Only five of those 11 trucks were actually in the window that we were looking at in order to develop this cost. Not all 11 impact this number, but five of them do, and then they're reflective as being a little more expensive than the typical replacement in that process. The only other thing I can think of that's embedded in that number, which is something coming from another direction is you know we recognize that when the City goes to replace a piece of equipment, they will oftentimes be able to sell that piece of equipment for something. We've taken an average of what those salvage sales have been over a historical period and use that as a partial offset to this number. That $923.000.00 is actually a slightly lower number than what it would be but for the recognition of those offsetting salvage sales.

Chair Suttmiller: What I'm looking at and what's bothering me a little bit is in 2019 and 2020, I'm looking at about let's say $700,000.00 that wasn't spent to replace vehicles in those two years. That should have been because that was included in the previous rates that were approved for Gas, to take care of that, it didn't happen. Now how much are we spending at $923,000.00 to make up for that not happening and what happened to the money that should have been spent on new vehicles.

Rabon: Yes, and as I suggested there is a piece of this that is attributable to catching up, but because this is an average of seven years, four of them being historical years, that in and of itself is not a, you know this number is not reflective of just looking at that number and not averaging it out or mitigating it with some other historical years to buttress it. I didn't know if the staff had any other comment on this particular issue.

Rodriguez: Chairman Suttmiller. If I may. The purchases are on a schedule, and there are times that we have budgeted, we budget every year for the replacement of vehicles and equipment with each Utility. There are some times where there's a lag in between the purchases, so we may have budgeted in one year, but due to the lag that it takes for the equipment to be brought in, or to be finally paid for with that invoice, it may cross into another fiscal year. We do

budget yearly in our budgeting process to replace a number of vehicles and a number of equipment, so that way we are always on a schedule.

Chair Suttmiller: Okay, we can move on. I think I made my point.

Rodriguez: Thank you.

Rabon: The next issue I was going to discuss in this presentation is looking at the capital spending plan. The projected capital spending plan for the next six years is what's shown here on this slide. I'd like to go through it a little bit. One thing that's important to note is that this projected level of capital spending is meaningfully more than the actual capital spending the Utility has spent in recent years. This represents a higher level of capital spending than what the Utility has actually incurred recently. The first group of projects that were looked at as part of this process, and by the way, just for clarity, this capital plan is something that was developed by staff in coordination with their experts on this and we're using that information for the first category of costs was tied to rehabilitation projects.

The first line lists out the forecast and projects that would be funded in each of these years tied to rehabilitation. Now, in recognition of the meaningful level of funding that would be required for those rehabilitation projects which are ones that we have assumed would be paid for with cash directly from ratepayers in the year in which they needed to be spent, there was a modification to forego a portion of those capital projects as identified in that second line. If you add the first line and the second line, you'll note that it always equals a million dollars. The million dollars of cash blended capital project spending put into the Revenue Requirement, which you may recall from one of our prior slides, this is where that million dollars is reflected in the capital plan.

The next kind of group of projects are miscellaneous projects that include things like SCADA, there's also a number of projects that are tied to being funded through the 2015 bond issue that still has some remaining funds available, and then some building improvements. All those three lines are items that were identified as being funded from existing cash reserves. The funds available to pay for those projects are already funds that the Utility has in reserve specifically tied for capital projects.

The last line in this group of projects is related to development. That line item is a significant contributor to the overall capital plan, and one that was determined to be projects that could be funded through a new debt issue that I've referenced earlier. If you will take the first three years of those development projects amounts, it amounts to roughly $11 million in profit. Those were the projects that we assumed would be funded by this new debt issue, meaning we assume new debt of roughly $11 million to pay for the first three years of those development projects. When we get to the next slide you'll see the debt service forecast is inclusive of that proposed new debt issue.

Looking at that debt issue, this is kind of an overall summary of all the debt, the 2015 A Series debt is already existing debt outstanding, as is the 2018 issue. If you add those two together those are both existing debt that you have principal and interest obligations for right now. Then we also had the debt issue for the new development capital projects, and the estimated debt service payments on that new debt issue would be $900,000.00, roughly. If you add all that together it's roughly $1.5 million, of which remember we have a funding source external to the rates being set in this venue to pay for the 2018 Series Revenue Bonds. What the amount of dollars of debt service that is included in our test year is reflective of that net amount at the bottom, the $1.2 million.

With that, development of the overall Revenue Requirement, and costs that are included in it, we next move to looking at what it costs to provide service. In order to do that we sub-functionalized the Revenue Requirement into groups of costs related to different subfunctions of the Utility; for example, the first one transmission is our cost tied to moving the gas to high pressure distribution system around the City as needed to transmit it over longer distances. Then the low pressure distribution system is the portion of the distribution system that's getting it directly to the end users, whether it be commercial or residential users. There are a few customers on the very large commercial customers that actually take service directly off the high pressure portion of the system, but the majority of the customers do take gas at the low pressure throughout the distribution system. That's what these different groups of costs are intended to reflect. Then we have costs that can be tied back to meter services, customer related costs in the Revenue Requirement. The overall $13.1 million that we were looking at from the prior slide can get broken down into these subfunctions, and then we want to allocate those different subfunctions to different customer classes based off of some cost causal relationship that they have to causing cost. That's what the allocation basis in the middle column is identifying, is what's the basis we're going to use to put those costs to customer classes.

In the case of, for example, the first one, the transmission system, we're using the coincidental peak demand for this overall system in the peak month. In the norm and normalized peak just means that we've made the adjustment to slightly weather normalize that peak demand, so both the volume of gas sold by month, by customer class has all been normalized by looking at how the test year weather compared to a ten-year average of weather. The overall adjustment, it was actually pretty de minimis, it was a very small adjustment. Nonetheless, with that normalizing process, what that norm means is we've normalized those peak demands, and then to that same extent the volume down at the bottom.

It's important to point out at this point the $13.1 million number in the test year is the number we've been talking about up to till this slide, in this slide we started to add the other component pieces of the total bill, namely the cost

of the gas commodity, which for the purposes of just evaluating the bill impacts and looking at these rates, we've assumed a cost of $2.50 per dekatherm for the cost of the gas commodity. That will fluctuate over time and the pass through mechanism, the rate that is charged to customers will also fluctuate in order to balance that out over time.

The other piece of this that is included in the analysis that's previously in the prior slides have been excluded, was this cost for decarbonization cost. This is a funding mechanism that's been proposed to be able to allow for the funding of various energy efficiency investments, have customers to make their use of the natural gas utility more efficient, with the hope of reducing the amount of natural gas that actually gets burned in the process. This is not uncommon. There are similar type programs across the country. This level of funding was kind of a balance of what we saw in terms of benchmarking what other utilities in other places are doing, and also kind of the level of funding that was appropriate and desired by the City for the funding of this program.

If you take that overall Revenue Requirement, that now includes the gas commodity, where the previous slides did not, we've kind of turned things on the side and so now we've got a specific Cost of Service for residential customers, small commercial, large commercial, industrial, irrigation, and high volume. Those are the existing six customer classes that the Gas Utility serves. If you first of all look at the test year Revenue Requirement in the first column, it's just kind of identifying in total dollars of what the overall Cost of Service to provide service to those different classes would be, then it compares it to, well, what would be with the current Rate Revenue that would be developed by those customers under the current rates, plus the $2.50 for the commodity gas being passed through, so we've assumed kind of dollar for dollar that that cost gets passed through to customers in this column. Then we got the over under recovery identified for each of these customers. You'll see for example residential is relatively not too far off from its overall Cost of Service. The industrial customer class is very close under existing rates to its Cost of Service. There are a couple of classes that are meaningfully away from their customer Cost of Service, namely the small and large commercial customers, which we'll talk about in a minute.

The last column is an interesting column because it shows you what is the overall Cost of Service, so that first test year column, divided by the annual normalized sales for those customer classes, so take overall annual cost divided by overall annual sales in terms of dekatherms, gas volume sold, and it gives you that far right hand column. It is highest for residential and for irrigation customers, which is what we would expect based on the amount of infrastructure needed to get gas service to those customers versus the amount of gas that they are actually consuming. As you move from commercial customers to large commercial and industrial, high volume customers, you're seeing that average cost decrease, and that's just a function of much of this utility's cost being fixed cost related, other than the gas commodity there's very little in the overall Cost of Service for the Gas Utility that is variable, it's

a very fixed cost intensive business. As you're taking those fixed costs and dividing it over more and more gas sales, it's driving down that average cost per dekatherm. Before we even started this project, these results on the far right hand column are essentially what we would have expected to be the result. Not these particular numbers, but this order of magnitude and this shift of residential being the highest cost per dekatherm and then as you get to the larger and larger customer that that Cost of Service per dekatherm decreasing. I've gone a little while without asking for questions, so I'll stop there for a second just in case there are any.

Chair Suttmiller: There are no questions right now.

Rabon: Then we look at proposed rates, so all right what are we proposing to do for this. The first set of rates that I'm going to show you contemplate the Utility going immediately all the way to full recovery. This slide is actually broken up into two slides to be able to make it fit and make it be readable. The first three classes I'm showing on this slide are residential, small, and large commercial customers. The proposed rates, just looking at initially just at residential, the proposed rates reflect a modest increase in the access charge, and then an increase in the volumetric charge to make up the difference between what the current rates will generate versus what we target that they should generate. It is notable that we are not taking these classes all the way to their actual Cost of Service, because there's a slight, very slight over recovery from the industrial customers even under their existing volumetric rate, which we're keeping flat or remaining unchanged. Because of that, we're feeding back to the other customer classes a pro rata share of that small over recovery. These rates largely reflect the Cost of Service, but they're just fractionally below it, because we're recognizing that small over recovery for industrial.

Then the other item that's on this sheet is the decarbonization pass through charge which currently there is none. We're proposing that it be assessed at $0.15 per dekatherm. One thing that's not on here is the actual gas commodity cost which will be whatever it should be in order to pass through that actual cost to customers. We didn't show the $2.50 here that we were using as the placeholder for that cost, but that would also be pass through as it is now. That rate from this perspective would be unchanged from what the Utility is currently doing.

Small commercial and large commercial you'll note still also similarly have a relatively modest change in their access charge, but then a relatively significant increase in the volumetric charge in order to bring them much closer to their Cost of Service, like I said almost all the way to full Cost to Service.

The other three customer classes are your larger customer, well it's the industrial customers, the high volume customers and irrigation customers. The irrigation customers I'm also seeing a relatively significant volume increase in their charge, but even at the rate as proposed you'll note that it's

still pretty in alignment with what residential customers are being charged. It's also true that this is a very, very, very small class. There's very few customers and there's very little gas sales actually in this class. You would expect that under certain weather conditions their usage might spike, but in normal circumstances they don't use a whole lot of gas in the grand scheme of things. Industrial customers as we mentioned previously, we've basically taken their access charge at the fixed dollar cost per month and just rounded it for administrative convenience up to $860.00, but it's almost unchanged from what they're charging now. We've left the volumetric charge unchanged due to the fact that they are essentially sitting right on top of their Cost of Service at the current rates. Then the high volume customers, there's an adjustment to their access charge and then a more meaningful increase in percentage terms to their volumetric charge, here again to bring them very close to the Cost of Service. Questions?

Chair Suttmiller: I have none.

Snyder: I have no questions.

Rabon: Okay. Then we're going to look at the average bill for these customers based upon this proposal going all the way to full cost as we're calling it. You'll see for residential customers, so let me just step back and say, average bill is calculated as what's the total revenue from those customers, under current rates or proposed rates, divided by 12 to get it to the monthly number, divided by the number of customers. That's the methodology by which we're getting to average bill for the purposes of this table. You'll see for residential we're talking about an increase of less than $2.50 per month, and it's representative of around a 9% increase. The more meaningful increases are to the small and large commercial customer classes that are seeing more significant increases in dollars in percentage terms. Industrial customers are almost flat they're seeing a very small increase, reflective of the fact that they are very close to their Cost of Service. Irrigation is a little further away from Cost of Service, so they've got a little bit larger increase in percentage terms as compared to residential, for example. Then high volume customers.

It's important to point out that the last time the gas base rates were changed, those changes were implemented in 2011. That was 10 years ago. I think it's important to recognize that while these increases are not insignificant, it's also been a very long time since these've been changed, and so due to in part to the fact that it's been a long time that it's caused the need for these increases to be a little bit more significant.

Royalty: I'd like to ask the question. Could you give us an idea of the difference in the cost of gas from 2011, the actual cost of the commodity, versus what it is today? I think what it has done it's actually gone down instead of going up.

Rabon: Yes, I do not have in front of me that data, but that is consistent with the way that the trend has been over that time period for customers. It may be helpful

to think about this in that respect. Now I appreciate you bringing it up, is that if it's true that the gas commodity itself is less than it had been in 2011, or some time ago, the bills that the customers should receive under these proposed rates may not be as meaningfully different as this table would suggest because of that fact. Because in our analysis we're assuming the same $2.50 but if gas was actually $5.00 or something higher than $5.00 in 2011, then that would make this comparison 2011 to proposed substantially more equivalent.

Royalty: Okay, good. Thank you.

Rabon: I don't know if staff has any memory of 2011. That's consistent Paul with the trend but I just don't have any numbers in front of me that would tell me that.

Royalty: Okay. As we were looking at this I thought it was, that would be pertinent to have that because back in 2011 if the cost of the actual commodity has gone down, then what that does is it also negates part of this increase.

Snyder: I have two questions. Is there any discussion on the table as far as buying the commodity, of hedging the commodity? If you have, would it be over, can you get it out to like a three to five year period? Because things are changing in the world out there as far as now that we're ending fracking and all this kind of thing, prices are going to be fluctuating wildly. You said you put in like a little over two bucks as a placeholder. I can remember running the cheese factory and it went up to $16 a dekatherm. That was a shock. Is there any discussion about hedging any at this time?

Rabon: I'm going to allow staff to speak to that because that's not in my scope of work.

Snyder: Okay.

Walsh: Mr. Snyder. In today's world we don't necessarily hedge on the commodity, we actually do monthly purchases for our baseload. We actually have a gas analyst on staff. We work closely with the pipeline, as well as with our suppliers. What we've done is we've tried to diversify our purchase portfolio by not just having a contract with Shell. We have contracts with NAMEA, we have contracts with Kansas under the PEAK contract and we have contracts with Shell Oil, where the majority of our gas comes from. We have several long term purchasing agreements, delivery agreements, we have short term agreements. We try to balance that in order to obtain the best price for our customers. The problem with the gas commodity is it's an unregulated market. You're right, if the market demand is $16 per dekatherm, that's the market demand and that's the only way you can buy gas. We have quite a bit of options implemented. I'll give you an example. We just went through this Arctic weekend with the state of Texas. I think gas got up to $300 a dekatherm in some parts of the country and even $1,000, a dekatherm in the Midwest. There was no way to protect against those types of fluctuations. When you're

looking at long term purchases, and long term contracts, we do, do that in today's world. We keep multiple contracts. We're actually looking at even more options to diversify that purchasing portfolio.

Snyder: I was dealing with Mario Puentes and we initially started out just our company, signing up for a five year program to keep that shock from happening again. Then the last time I was with Mario we were dealing with a one year contract through whatever company you could get the natural gas through, but it was a one year contract. Now you're saying there's nothing out there.

Walsh: No, no, no. Not that. We still offer the same sort of options to our industrial customers like NMSU and the dairies and people who are large users. Those options are out there. We do have a very, I want to say we need to take steps to make our purchasing portfolio even more diversified. There are several options and we do have long term and short term contracts in our portfolio, so those options are there. We try to do the best we can to keep that commodity cost as low as possible. As a Utility you're right if there are going to be changes in fracking laws or in fossil fuel resources that we can't predict that today, but we can prepare for it. We're actually working through the Utilities Board for energy transition and to make sure that we're leveraged and in a good position for those changes so we don't see those price shocks.

I know that's a very unspecific answer, but we are preparing for those changes. That's what we do every day, at the beginning of every month and pretty much daily is watching those prices and where opportunities are for us to even … I'll give Mario credit. I think it was last summer and the summer before he actually found excess gas in our system, in our transmission system and sold it back to other users. We had a couple of summers where gas prices were zero on the commodity for our customers because we sold it. We're monitoring that every single day. We are working to make sure that we have options in place in order to prevent those price shocks.

Snyder: All right.

Walsh: Mario, Joe, I don't know if you have more to add to that. I know that was a very broad answer.

Puentes: Yes, Mr. Chairman. Mario Puentes, Gas Business Analyst. Yes, we do look at it, Mr. Snyder, we still have those options that you and I kind of went through for several years. We can always lock in gas prices. Between 2002 and 2009 I would say, natural gas was the most volatile commodity in the world. At that time we pretty much didn't have a choice but to lock in because it was just so volatile. Since then we have locked in prices usually for the winter. The last two years when we were looking ahead towards the winter, it just seemed like the entity that we would be locking with was putting a little too much meat on its plate. We did not expect natural gas prices to fluctuate much last winter or this winter, and they hadn't other than this past February. Hedging would not have done us any good then, unless you do a financial type of hedge, but

we still look at it. Prices were about $1.00 more 10 years ago than they are now. You're right that we do anticipate that there will probably be an inflation factor coming up because of some of the nationwide political rules. Plus the gas has found a market with LNG as we speak, and there's a lot of liquefied natural gas being shipped out. Five years ago, it was just a supply glut. That is really beginning to balance out between supply and demand. Yes, we will continue looking at that as we always have, and if we see some risk that we can avoid, well we definitely would take action to prevent price shock. Yes sir. That's all I have, Mr. Chairman.

Rabon: Perfect. Thanks very much for that contribution. Are there any other questions before I start talking about possible other options?

Chair Suttmiller: No, not for me.

Rabon: Okay. Thank you. If going all the way to the full cost was deemed to be too significant to do all at one time, we did develop two different scenarios, one in which we would take the more meaningful impacts that are on the small and large commercial customers and we would phase in those rates over a period of three years. The way that structure would work is that for those customers, instead of the volumetric charge, the fixed charge, the access charge would change as proposed, because the overall increase in that the element of the base rate is not all that that significant. For the significant change in the volumetric rate charge, we would adjust that in equal increases over the three year period.

The first proposal was to look at just limiting the phase in to the small and large commercial customers because they were the most impacted. The only other thing we did in that more limited phase in scenario was we assumed that for all customers, the decarbonization rate would be phased in over those same three years. Fewer dollars now to $0.05, then to $0.10 and then ultimately to the $0.15 in the third year. We do that for all customer classes in the limited phase in option.

The other option we looked at which we're going to look at numbers here in a moment, but I wanted to kind of lay the framework. The other option we looked at was, well, what if we phase in those volumetric charges for all customers, and so that then became another scenario that we looked at that we'll see here in a moment. Looking at the limited phase in that is inclusive of just modifying the phase in for volumetric charges for small and large commercial customers, the rates themselves would look as shown on this screen. As I mentioned the access charge goes directly to the ultimate rate that we're suggesting, but the volume charge makes equal incremental steps over the three years to ultimately get to the rate ultimately proposed for those customers. That's what the rates would be.

What would be the corresponding average bill impacts under that scenario? Well, here again we're showing changes in the overall phase in of the ultimate

rates for all customer classes, because remember we're phasing in the decarbonization rate. The primary customers in this limited phase in that receive the most significant modification to their rates over the phase in period are these small and large commercial customers. You'll see that for their average bill it more modestly incrementally increases over *(inaudible 1:27:21)* ultimately get to the third year is essentially equivalent to our ultimate phase in proposal. This is at the bottom just shows the year over year increase for each of these customer classes from one year to the next. The most mitigation is here in small and large commercial customers.

In addition to there being an impact on the average bill for these customers, there's also an impact to the Utility. This is showing you what the financial impact would be on the Utility of waiting for three years to ultimately get to full cost recovery for those two customer classes, the small and large commercial. This is looking at making a few assumptions, one of them being that the operating O&M costs are the same in each year, the customer count and the consumption are all the same in each year. We're just trying to simplify the comparison from year to year, and so we didn't make any assumptions *(inaudible 1:28:31)* changing. You'll see that as a result of this whereas ultimately the proposed rates would get you to a debt service coverage number of approaching 2.4 times debt service coverage. In the near term, the coverage would be more modest. Now this still satisfies the policy of a 1.6 times being a threshold minimum target, but it is less significant. It also means that of the funds available to pay for capital projects, meaning vehicles, equipment, and the actual capital improvement plan, that six year timeframe of capital projects that were identified, those would need to be delayed. This at the bottom is just showing you the dollar amount of that delay. In the first year of the $1 million that's supposed to go towards capital projects, and the $923,000.00 that's supposed to go towards equipment and vehicles, you would be foregoing in the first year $821,000.00 of that amount. Meaning that the Utility wouldn't have those dollars generated from rates to make those capital investments. In the year two that gets cut in half, and then year three you're ultimately finally arriving at the overall level of capital spending that was forecasted for the Revenue Requirement. Any questions about this this impact before I show you anything further?

Royalty: Yes. When we talked last week I think staff was going to actually put together kind of a listing of projects that may be delayed and/or whatever as far as that is concerned. Did that get accomplished?

Rabon: I'm going to allow staff to speak to that particular question.

Rodriguez: Chairman. We do have projects that would be pushed back. The way we do our CFP is more like buckets of money, so we would have to push back some development projects. We really want to keep the rehabilitation. It's more of those development type of projects.

We're looking about a million, up to $2 million. Like I said it is really our development projects. We have projects that are scheduled in fiscal year 2022 that we have in our CIP such as a Del Rey high pressure extension. We have some projects, there was one here, kind of some, like I said, different things so easy lay replacement of PVC gas lines. This could also relate to additional SCADA projects, that's our monitoring system for the Gas Utility. That would be some, and then every year it just kind of would push it back. Then other projects depending on what is needed then those would be pushed back and then it would push back other projects. I can tell you the projects in that first year, and then from there it would have to depend on what we have going on. Those are some projects.

Royalty: Okay. I was just wondering if that was accomplished and so that's good. Appreciate it. Thank you.

Rodriguez: You're welcome.

Rabon: Any other questions about this particular slide? We also as I mentioned looked at the possibility of okay what would happen if we phased in rates for all classes. Here again I'm going to split this out over two slides so that the numbers wouldn't have to be so small. We are taking the access charge all the way to the ultimate proposed rate but then making the volumetric charge equal increments of increases over the three year period, and doing that not just for small and large commercial, but for all customer classes. This is showing you for residential, the small and large commercial, this proposal is exactly the same as the prior limited phase in and we were just looking at. Then for industrial we are keeping their volumetric charge unchanged under this proposal. Then irrigation and high volume customers will see the change in their volumetric rate as shown.

For them then you will see this up at the top shows you that the average bill for each of the classes over each of the phases, and then the bottom shows the year over year increase in that bill over time. Here again residential at the end of the day is looking at roughly $2.50 per month increase in their bill. In the grand scheme of things and given that it's been 10 years, that does not seem like an onerous adjustment to make to somebody's bill all at once, but this is really showing what that phase in would look like in terms of bill impact.

Then we look at the impact on the Utility. As you'll see in this first year that means that the Utility's going to not have capital dollars that the Revenue Requirement indicates would be appropriate levels of funding to the tune of $1.3 million in the first year, $650,000.00 in the second year, and then ultimately the third year achieving the full funding that we targeted. Meaningfully also the debt service coverage calculation for the first year would be down at around 1.5, below the 1.6 threshold that is targeted.

Royalty: Would you explain what the 1.6 threshold is that you're talking about there is that?

Rabon: Yes, I'd be happy to. Thanks Paul for the question. The 1.6 times threshold is a financial policy that the City would like their overall Utilities to achieve in terms of levels of debt service coverage. Off the top of my head, I don't recall what the covenanted debt service coverage ratio is which would be kind of the level that's required in the debt covenants themselves. This is the financial policy target that allows the Utility to make sure that they don't end up in technical default as a result of the coverage falling below what is contained in the debt covenant. I apologize for not having that information readily in my head, but if somebody on staff may or may not happen to know what the covenant coverage requirement would be. It's typically, 1.25, 1.4 somewhere in that that range.

Rodriguez: Chairman Suttmiller, Mr. Royalty. 1.4 is what is recommended by Moody's and I believe the City is 1.2. We recommend as a Utility maintaining a 1.6 times debt coverage ratio.

Royalty: Okay. That's what I wanted to know. That's what I wanted to know. Thank you.

Rodriguez: You're welcome.

Rabon: Yes, absolutely. I will contribute to that that target is an alignment with what we often see as financial policies for gas utilities or other utilities, water, wastewater, electric utilities as well. That is not inconsistent with the targets that are often established for these types of utilities. They're also pretty well in alignment with the overall actuals, maybe even a little bit on the low side, compared to the actuals that utilities are achieving in their peer group. Just as a point of reference.

Chair Suttmiller: It's my understanding, it has been my understanding for a long time, that that protects our bond ratings, and makes sure that we don't slide down below that 1.4 that Moody's wants and that would affect our bond rating. It gives us some recovery time. Am I right on that?

Rabon: You are 100% right on that. This coverage ratio is a key indicator that is looked at not only by the rating agencies when deciding what the appropriate rating to assign to a utility, but also the lenders of capital are looking at that as an indication of how comfortable, how assured they can be that you can make your debt service payments. The higher that number is, the more comfortable they feel they're going to be repaid. Amongst the other requirements that lenders of capital will make such as the requirement to have perhaps a separate reserve set up for one year's worth of debt service or other requirements they may put into the covenants requirement, it is very common for them to also spell out that the utility should maintain at a minimum this identified level of debt service coverage ratio. The idea is that the utility needs to be planning for and targeting something sufficiently above that covenanted requirement. Because you don't want to fall into technical default on your debt

simply because natural variations in either expenses or revenues. Yes, so all of this is being looked at by lenders of capital rating agencies to assess the creditworthiness of the utility and it will be reflected in interest rates correspondingly.

Chair Suttmiller: I also remember being told several years ago that the 1.6 figure, when we maintain that puts us in a higher level when getting state bonding or going under state bonding projects. I don't remember when that was told to me, but I think it is true. When we go after state funds, state bond, the 1.6 puts us way up there nice rates or down there with nice rates, I guess I should say.

Royalty: Grant. Could you go back one or two slides to the one that shows the phase in. That one. 1.84 is where we are on the limited phase in. I didn't remember what it was, so I appreciate that. Thanks.

Rabon: Yes. No problem at all. This gives you a sense of what the tradeoff is for accommodating a more modest rate adjustment. Just my comment here is keep in mind that it's been 10 years since you've adjusted rates. The cost of the gas commodity which is not included in the rate proposal that we're putting together, it will be whatever it will be, but that will also impact the bill, so to the extent that gas rates are going up or down that will make a direct impact on a significant percentage or proportion of the overall bill that's not really under the direct control of the utility or included in these rate changes.

With that background, I wanted to take a look at a little bit of benchmarking. Before anybody reads too much into this slide, I want to make one observation that this slide, for the purposes of the small commercial customers that are shown in this particular slide, we're showing them at a bill that would be reflective of roughly 167 dekatherms per month gas consumption. I picked that number because on a future slide I'm looking at customers that happen to be sitting around the midpoint of each of your customer class break points. For example, small commercial customer classes defined by gas consumption somewhere between zero to 4,000. This was on an annual basis. This bill was reflective, okay what if a customer was sitting right in the middle of that midpoint of that and consuming 2,000 dekatherms per year, what would that be on a monthly basis, it'd be on an average 167 dekatherms. That's the source of that, the basis for that assumption. It is meaningfully higher to the tune of maybe 10 times as high as what the average small commercial customer is consuming. We have also slides that show the average bill for these customers and they're meaningfully lower bills than what's shown on this slide.

With that, preamble, this is showing a representative bill based on the assumption of 3.5 dekatherms per month for residential, which is pretty close to the average over the course of a year for residential customer. Then this much larger consumption for small commercial. The far left side is reflective of the current rates, and then one over to the right is reflective of the proposed rates. That's the full phased in rate, once it goes to the ultimate rates that

we're proposing. Then we're showing a similar bill for New Mexico Gas Company and Zia, which are also gas providers in your general area. It's important to point also that this particular comparison is of the base rate portion of the bill only, so we're not showing the cost of the gas in this comparison, although we'll show that in future spot.

This is showing what would be the expected bills with a phase in for residential and small commercial customers. Critically for the residential customers, we're assuming that they're not getting a modification for this phase in. On this worksheet is primarily the phasing in of rates for small commercial customers. There are small changes in the residential bill because of the decarbonization charge changing over time, but predominantly for residential there's very little rate accommodation there. That's why you see the bill is pretty similar, whether you're talking about the full cost, year one, year two, or year three of the proposal, it's they're all kind of right in the same area.

Rabon: For smaller commercial the bars on the right hand side, this does include $2.50 cost of commodity gas in these bills now. Now we're comparing a total bill, not just the base rate portion. In this case here for small commercial we're looking at the average gas consumption for these different rate classes. We move from current in the dark blue bar, to the orange, ultimately where the full cost bill would be reflected. Then the gray, yellow, and light blue are just the three steps that you can take over three successive years to get there.

Also wanted to just kind of show you what the rates are for the two other nearby utilities that are providing natural gas service. This is showing the Zia rates, the current rates for these customers. There is not complete uniformity in translating between Zia's customer classes and the existing Las Cruces customer classes. They just don't line up perfectly because they're not just defined the same way. They're not the same and they're not defined the same way. There's a little bit of translational error when you're looking/comparing the rates that are shown here. Generally speaking for Zia's rate structure, their volumetric charge is $2.95 per dekatherm for all customer classes until you get to the large industrial customer class, which is then at that point there's a break or reduction in the volumetric charge. Whereas for the existing and the proposed rates of Las Cruces there's kind of a more gradual difference in charge based off of more of what the Cost of Service for each customer class. If you were still looking at Zia in particular for comparison purposes, if you were to look along the left hand side you've got a bill based on the assumed monthly gas consumption that's listed in that column. Here again for residential it's 3.5, small commercial is 167. That here again is a much higher consumption of gas than the average small commercial customer uses, but it's reflective of kind of the midpoint of that customer class in terms of where that would be in consumption.

This here, again is just the base rate portion of the bill, we're excluding the gas commodity and just comparing the rates that'd be changed as a part of this process, the base rates. Across the board for these sample, for these

particular assumed consumption amounts across the board for all these classes, what the Las Cruces bill as proposed after full implementation is modestly or significantly below the bill that a Zia customer would see.

Then we also looked at the New Mexico Gas Company rate structure. In this I thought it was kind of important to kind of provide some context for how they define different customer classes and their rate tariff. You'll note that, so New Mexico Gas current rates are at the top, and the proposed rates for Las Cruces are at the bottom. You'll note that the small commercial class for New Mexico Gas Company includes consumption up to a relatively large volume of gas. Small commercial almost might be a misnomer when thinking about their customers and who's paying those bills because of the significantly larger amounts of gas that are included between the cut offs of their various customer commercial classes.

In terms of the residential bill, the access charge itself it's modestly higher under the proposed rates for Las Cruces, but meaningfully the volumetric charge as proposed for Las Cruces residential customers as shown here is lower than the volumetric charge that New Mexico Gas Company residential customers would pay. That's also similarly true for the larger customers of Las Cruces, the industrial, high volume customers, these rates are comparatively more advantageous on the volumetric charge under Las Cruces proposal as compared to what the existing rates for New Mexico are. The place that there's a difference going the other direction would be the small and large commercial customers who are showing a more significant volumetric rate than is existing in the current rates for New Mexico Gas. Here again, part of that is explained by the fact that they are tapping into that small commercial class, customers that are actually fairly big customers which is driving down their cost of service for that class as a whole. Therefore that volumetric rate can be a little bit lower, even if the cost of providing service were completely equivalent between these two utilities, the base cost of service would be equivalent. Because of the nature of the customers that they're putting in their class, they're driving down what needs to be charged to the customers as a class. The result of that is larger customers are paying more than they would have to pay if they weren't lumped in with the small commercial customers. The small commercial customers are paying less than they should be paying to recover their full costs. If I've confused anybody please ask a question.

Then for New Mexico Gas Company we're looking at bills under these assumed volumes of gas consumption what the bills would look like as compared to the proposed fully implemented bills for Las Cruces. For residential it's diminished minimally, it's almost the same bill. It almost doesn't make a difference. Here again this is comparing base rates only, so we're not comparing gas costs between those two utilities. The small commercial, large commercial or as expected more meaningful difference, once you get to be a large customer, a large gas consumer, I should say, the rate structure under the proposed rates is meaningfully more advantageous than what the bill would be coming from

New Mexico Gas Company under their tariff. That may be the end of my presentation. I've reached the end of the slides.

Were there any questions that we had along the way that I either didn't address or didn't … there is. I apologize. There's one thing I failed to mention along the way that I intended to mention. There is a cost the Utility incurs related to regulatory costs, that are costs that are not directly really in the control of the Utility. Those costs can vary significantly and have increased year over year. The rates as proposed is that there's a certain level of funding for regulatory costs that are embedded in base rates as proposed, to the extent that next year or the year after or thereafter the cost of those regulatory costs has increased above what's embedded in the base rates. That incremental piece, that increase in cost, would be passed through to customers through a new rider that would be designed just to recover that incremental cost and rotatory costs. That was something that wasn't specifically listed in the proposal because the proposal would be at least initially that that rate would be set at zero. It would be a means for the Utility to over time be able to recover those costs as they were kind of outside of the control of the Utility. Were there any other I guess issues or topics that I either went over too quickly or you would like to delve into?

Chair Suttmiller: Not on my part.

Royalty: I've got a couple of questions for staff once you finished over there.

Snyder: I have no questions.

Rabon: Okay, well great. Well, I'm going to stay just in case while you're talking to staff something comes up and I might be able to answer something.

Chair Suttmiller: Okay. All right.

Royalty: A couple questions I've got is there a plan set out so that we have public participation? And I'll assume that to be through the internet, and actually have a presentation for this process to go through so we get some feedback from the public. Then that being the case, what is the anticipated start date for these rates that would be.

Rodriguez: Chairman, Mr. Royalty. The next step would be for me to bring back in April at the next meeting what we would like to do for public outreach. It will be through the internet. I have met with our community engagement person with the Utilities and she's given me the steps on how to do it. There will be a presentation. We usually have two, we have this one that is provided by the consultants because it was made available to the public. We usually use this one as one. We also use another presentation that is tailored to the UCAG, so that way the community could see who the UCAG is, what they do, and then it also gives a brief section in the presentation about what we're wanting to talk to them about. I will have those at the next meeting for you to review

and then vote on if those work for you. If you have any changes, you would approve them, and then I would use that for public outreach moving forward.

My plan is to start public outreach after the April meeting. I don't have an exact date yet. I will have to again in the next meeting go over the steps, because there's a couple of different things that I need to get ready for the public outreach. Then I will let you know the dates. We usually try to do a about a month of public outreach. Then once that month is done, then I will come back to the UCAG and provide all the updates that we received from the public.

Royalty: Okay. Then my comment is then once that's done then we would select one of the levels that we talked about, where it be the full, the partial, or I'm talking about delayed payments here, so where we would do that and then what we would recommend to City Council or whoever.

Rodriguez: Chairman, Mr. Royalty. Yes, so at the meeting in May, if it turns out to be that's the timeframe and we're able to meet then, if not, it'll be in June, I will come back and give you the input from the public, then the UCAG will make their recommendation to the Utilities Board. At that time you would again like you said pick either the full cost, the limited phase in, or the full all classes phase in, then that's the recommendation that would go to the Utilities Board. We write that up in I believe I do it in a resolution. We usually ask that the Chair come, provide input for it and then the Board will then make their decision on whether they would take the UCAGs recommendation or if they would like to provide their own recommendation to City Council.

Royalty: Okay. That's what I wanted to know.

Rodriguez: Yes sir.

Royalty: Thank you.

Rodriguez: You're welcome. And I also have, Chairman Suttmiller, you had talked about the personnel increase. The increase from 2019 and 2020, and the test year, so that includes 2.5% of personnel salary increases that are mandated by City Council and downtown. That also includes health insurance increase of 15%. Those do come up to about the $1 million, and then that budgets for 57 employees, like Ms. Walsh, the Utilities Director said, our increases include those vacant positions because we have to make sure that we have enough in there for them if we do hire. That's what it is. The 2.5% of personnel salary increases, and then 15% for health insurance.

Chair Suttmiller: Well we haven't gone on a hiring binge of totally new employees. Sounds good to me. Thanks so much for that.

Rodriguez: You're welcome. Thank you.

Chair Suttmiller: Okay, if that's it. Does anybody else have questions of staff. If we don't we'll move on.

7. Other Items of Interest:

Chair Suttmiller: Other Items of Interest. Does anybody on the Board have anything they want to bring up or anybody still with us on public participation?

Royalty: I want to bring up an item that I think needs to be expressed in our presentation in the outreach, and that is the fact that this $0.15 that we're getting for decarbonization, that's going to be used for energy efficiency programs. Then that then would be spent for the customers to help pay for the customers to do energy efficiency programs in their homes typically or in a business. The type of things that that would pay for is like the blower door test or duct sealing, that sort of thing. Those energy efficiency programs, that needs to kind of be explained because that $0.15 hasn't been there before and the purpose would be then those people that take advantage of the programs, then would basically get some of their money back, if that's what I'm saying. I think that needs to be a part of the program.

Chair Suttmiller: With the $0.15 is for needs to be totally explained. Yes, on the things that go in. I'd also like to say from my point of view, if any Board Member has anything that they want for the utility that be included on it, just send it to Dominique and she can figure it out where it doesn't need to come through me. If you got a good idea, send it in. Okay, any questions on that?

Royalty: No. That's good. Thank you, sir.

Chair Suttmiller: You're welcome. Since we have no further items of interest.

8. Committee Discussion:

Chair Suttmiller: Let's go move to Committee Discussion. Do we have any further discussion within the Committee that anybody would like to, has to say anything on? Okay, I'm going to take that as a no.

9. Next Meeting Date:

a. April 14, 2021

Chair Suttmiller: We move to the Next Meeting Date. The next meeting date should be April 14, 2021. Does anybody have any problem with that date or does it cause anything where we wouldn't be able to get up a quorum? I'm going to think that we three that are here now have got to make sure that we have that date clear or let Tanya know as soon as possible if you're not going to be available. Because it's the three of us that I think we can depend on right now and until we get a replacement for our departed colleague it's going to stay that way. Any discussion or anything that you have?

Snyder: I will be available.

Chair Suttmiller: Okay. I will make sure that I'm available.

Royalty: I'm looking right now at my calendar so hold on here just a minute. We said that was April the 14th.

Chair Suttmiller: Yes sir.

Royalty: Yes sir, I'm available.

Chair Suttmiller: Okay, that was great.

10. <u>Adjournment:</u>

Chair Suttmiller: The next one is adjournment. Do I have a motion from anybody that wants to go home or wants to get off the screen?

Royalty: I will make that motion that we adjourn.

Chair Suttmiller: Okay.

Snyder: I'll second it.

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Chairperson