Docket:	:	R.11-02-019
Exhibit Number	:	DRA-05
Commissioner	:	Florio
ALJ	:	Bushey
Witness	:	Delfino

DIVISION OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

DRA Report on the Pipeline Safety Enhancement Plan of Pacific Gas and Electric Company

Pipeline Replacement and Hydrotesting Cost Calculations

San Francisco, California
January 31, 2012

574154

TABLE OF CONTENTS

EXECUTIVE SUMMARY

The level of design for the pipeline replacements and hydrotesting of existing pipelines is at the concept phase and the cost estimates provided by PG&E are also at a similar level of definition.

To verify PG&E's cost estimates, an oil and gas industry estimation process (Industry Estimates) has been used to develop cost estimates that are what would be expected from bids plus 40%. At the conceptual design phase, it is standard practice to over estimate costs as a way to capture unknowns.

The pipeline replacement cost estimates for PG&E and Industry Estimates nearly match for the 36" pipe range. The smaller size ranges, which are the bulk of the replacements, differ substantially. The Industry Estimates are 48% of PG&E's estimates for the 10" pipe range, 62% for the 16" pipe range and 77% for the 24" pipe range. Differences between Industry Estimates and PG&E's estimates have little variability across the three levels of work location congestion.

Onshore pipeline construction costs are dominated by the labor and equipment required to dig the trench, lower the pipeline into the trench and refilling of the trench. Since the Industry Estimates use a rigorous method for determining the trenching costs for each pipe size range and the PG&E estimates appear to have been scaled down from the 36" pipe range, it is recommended that PG&E rework the trenching costs as a first step to rationalizing their estimates.

The cost hydrotesting of existing pipelines has three components: accessing the pipeline; filling the pipeline with water and pumping up to test pressure; removing the water from the pipeline and drying the pipeline back to operating conditions.

PG&E's cost estimates have overlapping work tasks in the lump sums for mobilization/demobilization and the per foot rates for actual hydrotesting. Industry Estimates have been made for direct hydrotesting costs and lump sums for mobilization/demobilization and "move arounds". The routine maintenance tasks included in the PG&E estimates are not included in the industry estimates.

The Industry Estimates are $12 to $18 per foot lower than PG&E's direct hydrotesting estimates. This may be mostly attributed to not including routine maintenance tasks in the Industry Estimates. PG&E has added 25% indirect costs to direct costs to get to the estimated "All-In Rate". These indirect costs are called into question by PG&E's inclusion of AFUDC at 5.24%.

Mobilization/demobilization lump sums estimated by PG&E are $500,000 without any respect to the size of the pipeline and the amount of equipment required to conduct the hydrotest. Industry Estimates are $86,000 to $140,000, increasing by pipe size. Industry Estimates are based on a cost that PG&E provided as an estimate to access a pipeline to investigate In Line Inspection anomalies and the equipment needed to conduct the complete hydrotest procedure for each size of pipe.

Move around lump sums estimates by PG&E range from $200,000 to $500,000. After determining that a "Move Around" is about half of the tasks involved in Mobilization/demobilization, the Industry Estimates were based on digging one access hole and moving 60% of the equipment. Industry Estimates for Move Arounds range from $45,000 to $77,000.

Better definition of the tasks required to conduct hydrotests will help rationalize the cost estimates. It is recommended that PG&E produce a design basis for hydrotesting and rework the cost estimates accordingly.

To get through 2012, priority hydrotests and pipeline replacements need to be identified by PG&E. The funding for the 2012 work should be based on Industry Estimates with a contingency to cover the unknowns. The definition of the work for 2013 onwards can be improved on during 2012 and estimates that are +/- 20% can be presented for approval at the end of Q3.

It is premature to make a final financial decision that is only supported by conceptual designs and cost estimates that are +/-40%.

CHAPTER 1 PIPELINE REPLACEMENT COSTS

I. INTRODUCTION

The cost estimates supplied by PG&E to support the request for ratepayer reimbursement are class 4 (more commonly referred to as conceptual design phase estimating). In the oil and gas industry, conceptual design is a project phase where the first round of economic viability is determined. There are many unknowns and the design work is rather broad to cover multiple concepts. As such, the reliability of cost estimates is low. The accepted tolerance for conceptual costs estimates is +/- 40%. There is a tendency to estimate towards the +40% so as to reduce the level of surprises in later phases.

As the project moves to the front-end engineering design phase, the best concept (meets capacity requirements with the lowest cost) is engineered to a level that bids for materials and construction can be assembled. Long lead-time items are ordered (so as to not extend the scheduled developed during the conceptual phase) with cancellation clauses. The tolerances on the cost estimate are reduced to +/-20% (mostly related to a higher level of engineering). A value assurance review is conducted at the end of front-end engineering design and management makes a decision to fund the project or send it back for further engineering. Once the decision to fund the project is made, bids are issued for the materials and construction services and labor.

Once bids are received and evaluated, a final cost estimate is made with a tolerance range of +/-10%. Management makes a final financial decision to go ahead with the project and fund the project for the final estimate plus a 10% contingency. Detailed design to undertaken once the construction contractors are selected and the construction equipment is known. The detail design is for tailoring the installation aides to the contractor's equipment.

Pipeline replacement is a straightforward process. At the concept phase, the wall thickness is selected at one standard thickness thicker than necessary to meet the requirements for pressure containment and human interaction zone factor. This allows the ordering of seamless line pipe to API 5L wall thickness tolerances without any worries about the minimum wall thickness going below the required thickness.

The process for developing the Industry Estimates was first used by the witness in 1998 to estimate the cost of a 45 mile 24” offshore pipeline[1] with a 20” branch line, a 12” branch line and four platform connections. This $100 million project was completed within $30,000 of the estimate. The estimation process has been used by Shell and Chevron for pipeline projects worldwide. The estimation process was used in 2011 to estimate costs for change orders for a subsea pipeline replacement project[2] in China.

PG&E All-In Model Costs

Diameter Ranges	Non-Congested	Semi-Congested	Highly-Congested
	Per foot	Per foot	Per foot
10” (< 12”)	$282	$489	$790
16” (14” to 20”)	$347	$618	$980
24” (22” to 28”)	$515	$841	$1,268
36” (30” to 42”)	$801	$1,253	$1,799

Onshore pipeline costs are dominated by the labor and equipment costs to dig and refill the trench for the pipeline. Steel prices, welding, anti-corrosion coating and pressure testing are the small components in the total cost.

The effects of zone classification for human proximity to the pipelines is mostly reflected in the amount of steel that is related to thicker wall pipe being required for higher classes. Welding times/costs are also increased for thicker wall pipe. All other work tasks remain the same except for the cost of handling the spoils from trenching based on the level of site congestion.

[1] Destin 24” pipeline for Shell Deepwater Development, Gulf of Mexico 1998

[2] Hui Zhou Subsea Reinstatement Project for ACT Operators Group, Offshore China 2011

II. SUMMARY OF RECOMMENDATIONS

The conceptual design phase cost estimates used by PG&E to develop the "All-In" costs are higher than Industry Estimates +40% costs. Across the levels of congestion for each diameter range, the estimates are 52% high for 10", 38% high for 16", 23% high for 24" and 7% high for 36".

There are two possible solutions to the high estimates: reject the estimates and recommend that PG&E revisit the estimates by using industry survey data as a basis; knock down the estimates by the percentages listed above with a revisit after bids have been received and evaluated for materials, labor, services and equipment rentals.

The costs of materials (and welding) that actually provide the containment and a comfortable level of safety are small compared to the cost of labor and equipment rentals to dig the trench and install the pipeline.

Insist on the highest quality materials and welding, while looking for ways to pare down the installation costs.

III. DISCUSSION / ANALYSIS OF DRA RECOMMENDATIONS

A. Line pipe materials selection

Since there are four pipe size ranges used for the conceptual design, seamless line pipe should be used as the basis for the 10" and 16" ranges and double submerged arc welded (DSAW) for the 24" and 36" ranges. 16" and 18" DSAW are available, but there are only a few pipe mills worldwide that manufacture to API 5L standards.

Simply adhering to API 5L is not sufficient to obtain pipe that meets the ductility requirements for greater than 20 year service life and ease of welding. Rarely has straight API 5L pipe been able to pass fatigue testing. Nearly all of the major oil and gas companies have specifications for line pipe that exceeds the requirements for API 5L.

The gain from a higher specification is that the pipe is more ductile and it welds faster. Both of these properties help reduce the construction cost of a pipeline project. They also make the life expectance of the pipeline significantly longer. With high labor costs, it is prudent to use the easiest to weld pipe.

PG&E has employed Gulf Interstate to provide the estimates for the pipeline replacement costs. The assumptions for steel grade and wall thickness are neither consistent nor supported. On a constructability basis, the diameter to wall thickness ratio (D/t) should be between 35 and 40 (example 20” with a 0.562” to 0.500” wall thickness). Any D/t that is greater than 40 is difficult to lift and lower into the trench, after it has been welded together.

The wall thickness design should always take into account the pipe being subjected to a 0.15% strain during installation in the trench. If the pipe does not have sufficient wall thickness, the strain will cause the pipe to become oval and result in a buckle in the pipe. There is a possibility that the buckle could run and flatten the pipeline.

PG&E selected the following diameters and wall thicknesses to use for the cost estimates

Outside diameter	Wall Thickness	Grade	Diameter/thickness	Min. Yield Strength
10.75”	0.250”	X52	43	52,000 psi
16”	0.312”	X52	51	52,000 psi
24”	0.375”	X60	64	60,000 psi
36”	0.500”	X70	72	70,000 psi

Based on the PG&E selected wall thicknesses, there may be no way to weld the pipelines outside of the trench and lower the completed lines into the trenches.

The PG&E pricing of the pipe is in line with purchasing small quantities from a stocking agent. As such, there should not be an additional materials burden on the pipe price, because the purchasing fee has already been added to the mill price by the stocking agent.

B. Industry Estimates Pipeline Design Basis

With the amount of line pipe that PG&E will be purchasing over the next five years, it would be prudent to bid the supply of pipe to world-class mills. Since the delivery can be spread out over several years, the mills will bid based on production capacity availability and not rush ordering. The bid prices will be somewhere in the $1,200 to $1,500 per ton range, not $1,750 to $2,355 per ton used in the PG&E estimates.

A pipeline is a means of transport a fluid from one location to another without loss of containment.

To establish a wall thickness for each diameter range, the hoop stress equation (P*f=2*S*t/D) is used and an ANSI/ASME pressure class is applied.

Abbreviation		Units
P	Pressure	Psi
f	Safety Factor	
S	Specified Yield Strength	Psi
t	Wall Thickness	Inches
D	Outside Diameter	Inches
ANSI	American National Standards Institute	
ASME	American Society of Mechanical Engineers	

To obtain a +40% cost estimate for each of the pipeline size ranges, an overdesign of the pipeline is the most transparent. Designing to ANSI/ASME B16.5 600# class with X42 pipe results in wall thicknesses that will cover all safety factors. This method does significantly overdesign wall thicknesses for pipelines in non-congested areas.

A 600# class design for -20 to 100^{o}F is 1480 psi. The resulting wall thicknesses for 1480 psi allow the pipeline to be used at a 0.50 safety factor for systems that operate at 740 psi. This is an overdesign, but it establishes an upper limit on the steel and welding costs.

To simplify welding operations and lower of the finished pipeline into its trench, wall thicknesses were selected keep the outside diameter to wall thickness ratio (D/t) to be between 40 and 35. This allows the girth welds to made outside of the trench and the finished pipeline lowered into the trench without exceeding 0.15% strain during lifting and lowering. Working conditions are also improved, as no work takes place in the trench with the exception of the two tie-in locations.

Steel prices were at an all time high in 2009. The demand for pipe was substantially reduced by the economic downturn and the moratorium on new drilling in the Gulf of Mexico in 2010. Current prices for the high specification pipe used for deepwater pipeline projects are still fairly high. Deepwater seamless pipe is costing $2,400 per metric ton ($2181 per ton). A December 14th, 2011 conversation with a category manager[3] for Chevron confirmed the bid price for deepwater specification seamless (a specification written by the witness).

With the amount of line pipe that will be ordered for this project, bidding the supply of pipe directly to mills worldwide is prudent. Since the pipe will be supplied over 5 years, the mills can manufacture on a space available basis. Prices should be substantially lower than what is being used in the estimates.

The type of pipe used for each of the diameter ranges is not going to be consistent. Smaller diameters are generally seamless, as double submerged arc welded (DSAW) pipe smaller than 18" is uncommon. For pipe 20" and larger, DSAW is the choice. DSAW is lower priced than seamless, as the steel plate used for DSAW can be made by more mills worldwide and there is less risk in producing off-spec pipe, as the properties of the steel plate are controlled before the plate is delivered to the pipe mill and any off-spec plate can be diverted to other products without loss of value. Off-spec seamless pipe is scrap, as re-heat treatment is rarely approved.

To get to a +40% cost estimate, all pipe is priced at $2,181 per ton.

C. Anti-corrosion Coating

Fusion Bond Epoxy (FBE) is the coating material selected by PG&E. FBE is the best coating for all pipelines and it is the industry standard. As long as the girth welds to join the pipes together are coated with FBE (post weld and nondestructive examination), the external corrosion protection for the pipelines will be the best available.

[3] Phone interview of Mike Quinney of Chevron in Houston, Texas Dec 14, 2011.

If heat shrink sleeves are proposed for covering the girth welds, there will be problems with external corrosion of the welds. When FBE coating is combined with a cathodic protection system, the synergy of a semi-permeable coating that allows the expelling of hydrogen that evolves from the area around damage to the underlying steel, but does not allow oxygen to pass through gives the ultimate in external protection for the pipe. Heat shrink sleeves are not semi-permeable and they can cause cathodic shielding, which results in an oxygen concentration cell at the heat shrink sleeve. The speed of installation is what the construction contractors are looking for, but the owners of the pipeline and the neighbors to the pipelines do not benefit in the long run.

The best coating available is fusion bond epoxy (FBE). It is the oil and gas industry standard and it works in conjunction with a cathodic protect system to provide the best protection from external corrosion.

FBE is usually applied to the exterior of the pipe at a coating mill. Berdero Shaw has a portable mill that can be moved to a location in California for coating all of the pipe. By coating close to the construction sites, coating damage during transportation can be minimized. Additionally, some pipeline segments may need special coatings to prevent the adhesion of the soil to the pipe. These "slick" coatings are applied over the FBE during the coating process.

Having the pipe coating under the control of the project team will minimize the quality issues and help to improve the overall quality of the construction. PG&E's assumption that the coated pipe will be purchased through an agent is a recipe for failure and cost overruns.

Since there are no viable internal anti-corrosion coatings, no internal coating is being considered and the extra wall thickness described in the section above can be counted in the corrosion allowance. Currently available internal coatings generally prevent corrosion, but areas not coated cannot be protected and result in concentrated corrosive activity taking place in these unprotected areas. The results are early corrosion penetration and loss of containment.

For the Industry Estimates, mill applied FBE costs about $3.35 per square foot of external surface. Included in this are: grit blasting, heating of the pipe, application of the FBE powder and cooling of the coating. Each 40-foot joint of pipe is coated with FBE, except for about 10 inches on each end. This is to allow the girth welds to be made without damage to the FBE. Post welding and non-destructive examination of the weld, the uncoated (field joint) area is grit blasted, heated and FBE coated. Field joint coating costs about $17 per square foot, as it is manual and labor intensive. To develop an estimate, the two costs have been combined on a proportional basis to arrive at a FBE coating cost of $4.00 per square foot.

D. Welding

There are two processes for making the girth welds that join the pipes together. Manual gas metal arc welding (GMAW) commonly known as MIG welding and shielded metal arc welding (SMAW) commonly known as stick welding are possible welding methods. The best available method is semi-automatic GMAW commonly referred to as Auto MIG welding. Auto MIG welding is computer controlled with an operator able to over-ride a few of the parameters. The quality of Auto MIG welding is superior to manual welds and is less dependent on the manual skill level of the operators.

Modern pipelines are welded together using automated gas metal arc welding (GMAW). This welding system lays down approximately 0.125" of filler metal per pass. Ideally, the wall thickness of the pipe is at least equal to 3 passes. This allows the each successive pass to heat treat the pass underneath it and the capping pass is the only non-heat treated filler metal. With the low heat input from GMAW, the heat-affected zone in the parent pipe is small and the properties of the pipe are not deteriorated.

The traverse speed that the automated GMAW can operate at is dependent on the chemistry of the steel in the pipe. Shell, Exxon and Chevron[4] found that straight API 5L pipe welds at 6” per minute and that improvements in the chemistry of the steel increase the welding speed to 15” per minute. The use of the better chemistry steel improves the welding time and the fatigue resistance of the pipe.

In high labor cost areas, it is strongly recommended that better chemistry than API 5L be used for the pipe, as the 15 to 20% increase[5] in pipe cost is eclipsed by the reduction in welding time by 2.5 times.

E. Welding Costs

Welding costs are directly proportional to the time it takes to make a weld. Welding time is controlled by the heat input that the pipe can absorb during the welding process, without changes to strength and hardness properties of the pipe. The micro-alloyed steel used in deepwater seamless pipe allows the welding heat input to be substantially higher than steel that simply meets the requirements of API 5L line pipe specification.

Weld filler metal layer	Function
Root Pass	Forms the pressure seal
Hot Pass	Reinforces the pressure seal
Fill Pass(es)	Builds thickness to match the wall thickness
Cap Pass	Adds reinforcement to the weld

Welding traverse speed (lineal speed to make a girth weld) for API 5L pipe is about 6 inches per minute for a 0.125-inch thick pass. With 10.75” 0.375” wall thickness pipe, the four welding passes will take 22.5 minutes to complete.

Deepwater specification pipe welds at about 15 inches per minute. The same 10.75” pipe requires only 9 minutes to complete all four passes. The value of using

[4] Internal studies by witness and others working for Shell, Exxon and Chevron, 2000-2008.

[5] Witnesses experience of steel prices 1998-2011.

high specification pipe is quickly recognized when the labor costs are high. The hourly rate used for a welding spread is $500.

For the purposes of developing a +40% cost estimate for the Industry Estimates, the slow speed for low specification pipe (6 inches per minute) is being used. This speed is equal to the speed for skilled manual welders. Combining the cost of deepwater specification pipe with slow welding speeds results in an over-estimation of the pipe and welding costs.

F. Trenching Costs

For land pipelines, trenching is the largest component in the construction costs. PG&E said little about the assumptions used in the estimate basis memorandum. Since there have been few pipelines built in California in the past 20 years, benchmarking costs against unit rates provided by a local construction company is very vague.

Based on the amount of pipeline to be installed over the next 5 years, more competitive rates can be expected, if the construction work is bid nationally. As such, the installation/trenching costs are grossly over estimated.

Since PG&E has said nothing about the value of the pipeline sections being replaced, it is likely that a pipeline recovery contractor will be removing the old pipeline and the scrap value is covering the cost of recovery. For pipelines larger than 10", the value of the used pipe exceeds the removal cost and the recovery contractor will be paying PG&E for the pipe and doing the removal. This is another piece of the work scope that has added to the cost over estimation.

To get a benchmark for digging and refilling pipeline trenches for the Industry Estimates, California Pipe Recovery[6] (a Bakersfield based company) was contacted. They gave a price of $8.60 per foot to trench and refill to a 3-foot depth for a 12" pipeline in a non-congested area. This translates to a cost of $1.40 per cubic foot of

[6] Phone interview of Kaaren Cambio, President of California Pipe Recovery Dec 15, 2011.

soil removed and $1.40 per cubic foot of soil refilled into the trench. To get to a +40% estimate, adding 40% to this cost results in a cost of $2.00 per cubic foot for digging and the same for refilling.

Area	Requirements	Multiplier	Cost
Non-Congested	Dig and stack spoils along trench. Refill trench from spoils stack. No compaction	1	$2 per cubic foot
Semi-Congested	Dig and stack spoils along trench. Haul away volume equal to diameter of pipe. Compaction for less than 10% of area paved (paving covered in right of way damage costs).	2.5	$5 per cubic foot
Highly-Congested	Dig and load spoils directly into a truck and haul away for storage. Haul soil back for refilling. Compaction of soil followed by paving (paving covered in right of way damage costs)	5	$10 per cubic foot

The highly-congested digging and refilling cost per cubic foot is close to the cost that was experienced by the witness for the offshore trenching for an 8" oil pipeline[7] in 200-foot water depth in 2006.

For the Industry Estimates, it was determined that to accommodate installing the replacement pipelines next to the existing pipelines, all trench widths are twice the diameter of the pipeline. To accommodate unknowns in the depth of the trenches, it is expected that there will be 6 feet of cover over the pipelines. As such, the estimated depth is 6 feet plus the pipe diameter. Since all work activities are to take place on the surface, shoring of the trenches is not included.

[7] West Delta 109 pipeline replacement project for Chevron Pipe Line Company, Gulf of Mexico 2006.

G. PG&E Indirect Costs

Since there is not enough information to modify the indirect costs from what is supplied in "Appendix 3.2 Estimate Unit Cost Summary Matrix for Pipeline Replacement Projects", all of the indirect costs are included in calculating the Industry Estimates "All-In Unit Costs".

H. Hydrotesting

Every new section/segment of pipeline will have to be hydrotested. This will not be a major cost per foot, but PG&E should break it out of the installation cost to recognize the impact.

Since new pipe is being used, there will not be a need to make multiple cleaning pig runs. There is still the need for cleaning the water removed from the pipeline before it is reused for another hydrotest or disposed of.

Overall, hydrotesting of new pipelines should cost (based on size) between $3 and $10 per foot (see Chapter 2).

I. Industry Estimates All-In Unit Costs

The following table summarizes the replacement cost per foot for the size ranges and congestion levels proposed by PG&E.

Pipe Size Range	Non-Congested Areas	Semi-Congested Areas	Highly Congested Areas
10"	$122	$242	$400
16"	$210	$383	$610
24"	$386	$650	$985
36"	$753	$1,170	$1,678

J. Industry Estimates Breakdown of the All-In Costs

Each cost in the following table is a per foot number estimated using the processes described in the document above.

Non-Congested Areas					
Pipe Size Range	Pipe & Coating	Welding	Trenching	Indirect Costs	Total
10”	$33	$5	$47	$37	$122
16”	$73	$11	$72	$54	$210
24”	$163	$25	$112	$86	$386
36”	$364	$55	$180	$154	$753
Semi-Congested Areas					
Pipe Size Range	Pipe & Coating	Welding	Trenching	Indirect Costs	Total
10”	$33	$5	$116	$88	$242
16”	$73	$11	$178	$121	$383
24”	$163	$25	$280	$182	$650
36”	$364	$55	$450	$301	$1,170
Highly-Congested Areas					
Pipe Size Range	Pipe & Coating	Welding	Trenching	Indirect Costs	Total
10”	$33	$5	$232	$130	$400
16”	$73	$11	$356	$170	$610
24”	$163	$25	$560	$237	$985
36”	$364	$55	$900	$359	$1,678

All direct costs are estimated at +40% over what would be expected from competitively bid materials, services, equipment and labor.

K. Road Borings

Road borings are not included in the “All-In” cost estimates, as not all pipelines require them. The need is determined by each section of pipeline and added in to those projects where necessary. PG&E’s adders for road borings and horizontal directional drilling (HDD) are not consistent. The cost for 10” is $674 per ft^3 of hole required, $474 per ft^3 for 16” and $240 per ft^3 for 24” and 36”. There is a good possibility that the cost for road borings and HDD will be higher than the estimates. As a conceptual design cost, these numbers may be fine as -40% estimates. Unless there are a large number of road crossings required, these estimates may not have a significant impact on the total cost. A revisit of these estimates is recommended.

IV. CONCLUSIONS

PG&E has not supported the majority of the replacement costs. There are oil and gas industry cost surveys that are published for pipeline construction annually. PG&E's use of unit rates from one contractor is not a viable benchmarking for costs estimates for funding of construction projects. Each of the cost categories needs to be revisited by PG&E and supported before moving forward.

Estimating pipeline construction costs is a straightforward process. It is all dependent on the definition of what size the pipe is and how deep is has to be buried. Onshore pipeline costs are dominated by the labor and equipment rentals. The more congested the construction area is, the greater the dominance of the total cost by labor and equipment rentals for trenching.

Defining how deep the pipelines are to be buried can go a long way to refining the total construction cost estimate.

CHAPTER 2 HYDROTESTING COSTS

I. INTRODUCTION

Utility grade Natural Gas is considered a clean product. The sulfide content has to be below 1 ppm, inert gas (nitrogen and carbon dioxide) below 4%, the heating value between 950 and 1050 BTUs and the water content less than 7 pounds per million cubic feet. The dew point of the gas is -20°F or lower. Since the gas supplied to PG&E has to meet these criteria, it is unlikely that there will be contamination inside of the pipelines from the gas. However, valve lubricants and a few other materials may have been introduced into the pipelines during operations and the pipelines were not subjected to routine maintenance pigging.

If black powder iron sulfide is present in the pipelines, routine maintenance pigging has to be done to remove it. During the actual hydrotest, any remaining black powder will be washed out. The floatation units and filters used for cleaning the post use hydrotest water will remove this material and prevent it from being released in any water that is disposed of.

PG&E Hydrotesting Costs

Diameter Range	Per foot	Direct	Indirect
10”	$30.49	75%	25%
16”	$39	75%	25%
24”	$45	76%	24%
36”	$59	75%	25%

The process of hydrotesting is straightforward. A section or segment of pipeline is isolated from all other inlet and outlet connections. The product inside the pipeline is removed: with gas pipelines, a compressor is used to transfer the gas to another section of the pipeline that is still in service. Test heads with pigging capability are connected to the two ends of the section to be tested. A pig is launched with water behind it and the line filling process begins.

To efficiently fill the pipeline, a pig speed of 5 feet per second is to be maintained. Using a pig to separate the water from any remaining gas in the line reduces the amount of gas trapped in the water. Once the pipeline is full of water, a process to remove the trapped gas by pumping up the pressure and releasing is initiated. This de-gassing/de-aeration can require up to 15% of the fill time to complete. After assuring that the line is gas/air free, the line is pumped up to full test pressure and held for 8 hours. The 8 hours is an ASME recommended practice that allows time for investigating pressure and temperature changes during the test, as visual inspection for leaks may not be possible.

During the test, pressures and temperatures are recorded. All volumes of water pumped in to make up for pressure losses and water released to compensate for pressure gains is recorded along with the temperature change that may have caused the gain or loss. Calculations are run to confirm that the gain or loss was related to the temperature change. If there are continued pressure losses, there is a leak that has to be tracked down and repaired before continuing with the test. If there are cracks in the pipeline that have not already been found, they will propagate in a matter of minutes upon reaching test pressure.

After the 8-hour test is completed, the pressure is released by bleeding the water through the water cleaning (CETCO[8]) system. The pipeline does balloon during testing and there may be 1 to 2% extra water in the pipeline than the fill volume.

With the CETCO units connected on one end of the pipeline and holding tanks and haul trucks ready, dewatering can begin. A pig is launched with compressed air behind it. A pig speed of 5 feet per second is maintained to efficiently push the water out of the pipeline and through the CETCO units. Cleaned water can be hauled to another hydrotest or pumped into the next segment for the next hydrotest.

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[8] CETCO is a Louisiana based service company that cleans hydrotest water for the oil and gas industry.

Once the pig reaches the other end of the pipeline, dewatering is complete and drying can begin. Drying involves pushing pigs down the line with compressed air behind them. It takes about 40 pipeline volumes of air at standard temperature and pressure to dry the pipeline back to operating moisture content.

If there is no more work to do on either end of the pipeline that has been hydrotested, a replacement short section of pipe is welded in to reconnect the pipeline to the neighboring pipeline. The access holes for the hydrotest work can be refilled.

II. SUMMARY OF RECOMMENDATIONS

The allowances and contractor provided costs for hydrotesting are far higher than Industry Estimates. Items included by PG&E in the direct costs are also included in the mobilization/demobilization costs. The indirect costs (calculated as percentages of the direct items) need to be revisited, as some items do not apply to hydrotesting and should not factor into the cost per foot for hydrotesting.

A rework of PG&E's hydrotesting estimates is needed. It would be wise to acquire hydrotesting services costs nationally and not rely on a local construction contractor for estimates.

A go forward plan would be to add a 25% contingency to the Industry Estimates per foot costs plus the Industry Estimates mobilization/demobilization and move around lump sums for hydrotests that are planned for 2012. The next 6 to 8 months can be used by PG&E to determine what belongs in the per foot costs and what is contingency for pipelines that are short on internal cleanliness. The mobilization/demobilization and move around costs can be better defined and clarified by PG&E during the same 6 to 8 month period. Hydrotesting for 2013 forward can be revisited after the estimates have been reworked.

Keep hydrotesting costs simple and use a contingency for the costs of unknown unknowns. A +40% estimate is enough of an over estimate to cover the known unknowns.

Plan the hydrotesting schedule to allow the water to be reused multiple times before disposal.

Refining the work scope of the hydrotests to minimize the number of tests while keeping water volumes reasonable will reduce the overall cost of the whole hydrotesting program.

III. DISCUSSION / ANALYSIS OF DRA RECOMMENDATIONS

A. Allowance for hydrotest pre-cleaning (brush and gel pigs) and water disposal

PG&E has included an allowance for pre-cleaning the pipelines before hydrotesting in their direct hydrotesting cost estimates. This cost should not be part of the hydrotesting costs. Pre-cleaning is a maintenance task and is an operating cost. The disposal of water from hydrotesting has nothing to do with this, as hydrotest water will be cleaned and reused for a following hydrotest.

B. Hydrotesting

PG&E's cost estimates per foot of pipeline for hydrotesting appear to be "book prices" that are substantially higher than the prices that would be bid, if the hydrotesting is tendered nationally. PG&E responded to a question about the source for their hydrotesting cost basis with the information that a local to California contractor provided the per foot estimates for testing and cleaning (dewatering) and drying.

Hydrotesting is a straightforward work task and the cost of mobilizing (demobilizing) equipment is covered separately. The actual pressure testing of a pipeline will cost the same for all sizes and lengths of pipe. The volume of water to fill the pipeline and the time to pump the water in is the cost that varies by pipe size. This was not reflected in PG&E's per foot cost for hydrotesting. Also, hydrotesting takes less time and equipment than dewatering and drying, but that is not reflected in PG&E's estimates.

The PG&E post test (pre commissioning) estimates are substantially lower than their hydrotesting estimates. This is unusual, as more equipment and time are required to remove the water and dry the line back to operating conditions. Dewatering and drying is also where the cost of cleaning the post test water should be.

The time to complete the dewatering and drying is a function of the speed that pigs can be run in the pipeline. The speed range for effective pigging is 5 to 15 feet per second. From the speed range, the number of compressors and the time can be calculated. It is a matter of how many for how long.

The Industry Estimates for hydrotesting costs are based on time of use for the equipment and the water. Based on industry rates for pumping equipment, trucking, air compressors and retail price for deionized water were used to develop the costs for hydrotesting.

Water Fill & Compressed Air Rates based on 5 feet/sec for water pigging and 15 feet/sec for air pigging

Pipe Size Range	Water fill rates	Compressed Air rates
10”	8,400 gallons per hour	50 cubic feet per minute
16”	8,400 gallons per hour	100 cubic feet per minute
24”	12,600 gallons per hour	200 cubic feet per minute
36”	12,600 gallons per hour	500 cubic feet per minute

Capacities & Costs used in the Industry Estimate

	Capacity	Rates
Water Delivered	4,200 gallons per truckload	$0.50 per gallon
Water Hauled Away	4,200 gallons per truckload	$0.50 per gallon
Truck mounted pump (Halliburton or Schlumberger)	12,600 gallons per hour	$1,500 per hour
Truck mounted air compressors (Weatherford or BJ Services)	100 cubic feet per minute	$1,500 per hour
Water cleaning equipment (CETCO)	12,600 gallons per hour	$500 per hour
Hydrotest recording equipment and technicians		$500 per hour

The above listed equipment and services, plus welding crew time to cut into the pipelines and reconnect the pipeline are used to develop the Industry Estimates for Direct Hydrotesting Costs.

Industry Estimates

Pipe Size Range	Direct Hydrotesting Costs per foot
10"	$7
16"	$11
24"	$17
36"	$33

The Industry Estimates are $12 to $18 per foot lower than PG&E's direct hydrotesting estimates. This may be mostly attributed to not including routine maintenance tasks in the Industry Estimates.

C. Allowance for replacing valve blow down stacks, branch connections, and other existing line taps

PG&E has used this nebulous catch all for reinstating the pipeline to operation, a function that should be part of the mobilization/demobilization cost on a case-by-case basis. This allowance belongs in a contingency category, not in the direct costs.

D. PG&E Indirect Costs

PG&E has added 25% indirect costs to direct costs to get to the estimated "All-In Rate". These indirect costs are called into question by PG&E's inclusion of AFUDC at 5.24%. There may be some merit to the indirect costs, but the percentages for: right of way, land acquisition and damages; engineering; construction management, QA/QC and owner's overhead are more in tune with pipeline replacement than hydrotesting.

The Industry Estimates do not include these indirect costs.

E. Mobilization/Demobilization Costs

PG&E has estimated that a mobilization/demobilization of $500,000 is required for each hydrotest irrespective of the pipeline size range. PG&E has replied to questions about what tasks are included in mobilization/demobilization with a general description of accessing the pipeline, moving equipment in and out and pre-cleaning the pipeline (which is also included in the PG&E hydrotesting per foot estimates). Pre-cleaning does not belong here either, as pre-cleaning is only required for pipelines that have not been maintained properly.

Since the mobilization appears to be digging the access holes to the pipeline and moving the equipment and demobilization is filling in the holes and moving the equipment, there is going to be a different cost per pipe size range. PG&E estimates that each hole they need to dig to investigate anomalies found by intelligent pigging will cost $40K. Back calculating this to a hole size, results in a hole that is larger than would be needed to access the pipeline to cut the pipeline and connect a test head (including pig launcher/receiver). For hydrotesting, a hole 25 feet long, 6 feet deep and 4 feet on each side of the pipeline is sufficient (the back calculated investigation hole is 30 feet long).

Digging and refilling

Pipeline Size Range	10"	16"	24"	36"
Volume of hole cubic feet	1,320	1,370	1,420	1,470
Shoring costs	$6,800	$6,800	$7,000	$7,300
Estimated cost using $10/cubic foot (same as highly congested area trenching) for dig and refill plus shoring costs	$33,200	$34,200	$35,400	$36,700

Once the access holes have been excavated and shored (the rental of shoring is included in the hole digging and refilling estimates), the set-up for the hydrotest can begin.

Equipment Required

Pipe Size Range	10”	16”	24”	36”
Pumps	1	1	1	1
Air Compressors	1	1	2	5
CETCO water cleaning system	1	1	1	1
Baker Tanks for 2 hour hold time	4	4	6	6
Water haul trucks (one more than is needed per hour of pumping/dewatering)	3	3	4	4
Hours to move in & move out equipment	6	6	10	12
Estimated costs based on full operating rates	$19,200	$19,200	$40,000	$66,000
Total for a hole on each end of the segment being tested and move in & out of the equipment	$85,600	$87,600	$110,800	$139,400

Before any work is done to hydrotest a section of pipeline, the line will have to be depressurized to confirm that the block valves are holding. The normal way to do this is to hook-up a small compressor to the blocked in section and evacuate the section while compressing the gas into the pipeline section on the other side of the block valve. If it is a short section of pipeline, they may choose to just vent the gas. Since we cannot determine the method for depressurization, add $20,000 for labor and the compressor to accomplish the task. We are looking at 4 miles of 36” or 5 miles of the other line sizes as the maximum that will be tested at a time; as such the volume of gas to move is not large.

Pipeline cleaning to remove debris and free liquids are maintenance work tasks and should not be included in hydrotesting. Any prudent pipeline operator will do their maintenance pigging on a monthly (if there are variations in the product in the pipeline) or quarterly schedule. At any time, the prudent operator’s pipeline could be shutdown, drained/flushed of product and hydrotested without having to go through a cleaning process.

Another item that may be hidden in mob/demob is the loss of business for the time that the pipeline is out of service for hydrotesting. Since the hydrotesting can be planned around customer needs, the loss of business due to hydrotesting should be handled by the contingency allocation.

F. Move Around Cost Estimates

The only reason for a move during the hydrotesting of a pipeline segment is that the length of the segment is longer than is ideal for water handling post hydrotest. If the 5-mile limit for smaller diameters (24" range and under) is held to, there will be a significant number of moves. Removing the 5-mile restriction and using the limit to water volume set by the 4-mile limit for the 36" range will bring the moves to a minimum.

The 4-mile limit translates into 36 miles for the 10" range; 20 miles for the 16" range; 9 miles for the 24" range. If this were applied, any hydrotests on segments shorter than these limits would have a simple mob/demob and no moves. The moves that will be chargeable would then be related to shortening lengths to reduce customer inconvenience caused by the lack of alternate delivery means.

PG&E has estimated move around costs to be: $200,000 for 10" pipe size range; $300,000 for 16"; $400,000 for 24" and $500,000 for 36". There has been no justification for these move around estimates. As such, the Industry Estimates has been based on the need to move equipment a relatively short distance from one location to another.

The logical use of moves is to leapfrog equipment. This is accomplished by leaving one end of the first section hydrotest equipment in place and moving the equipment from the other end to the next location. An example is to place the water cleaning and holding tanks at the mid point of the segment being hydrotested and the pump and drying compressors at the first end; after the first section is tested and dewatering begins, the pump is moved to the second end of the segment. Water that is being pushed out of the first section can be run through the cleaning system and trucked to second end and pumped into the second section. After the second test is completed and the dewatering begins, the water cleaning can take place without an equipment move. Either the water can be trucked to the next hydrotest or disposed of if there is no next test within a reasonable haul distance. Water use and disposal can be minimized.

Another use for used hydrotest water is it can be used to flush debris from pipelines that have not been maintained properly (no recent maintenance pigging).

Since a move involves digging (and later refilling) a hole to access the pipeline to cut into the line and install a test head, the digging and refilling costs calculated for mob/demob should be used.

Logically, only half of the hydrotesting spread is actually moved if the leapfrog method is applied. The question is which half is being moved. Since we do not know at this time, it might be fair to allow 60% of a full equipment move in / move out to be used as the other component to the move around cost.

Pipe Size Range	10”	16”	24”	36”
Digging & refilling				
Volume of hole cubic feet	1,320	1,370	1,420	1,470
Estimated cost using $10/cubic foot (same as highly-congested area trenching) for dig and refill plus shoring costs.	$33,200	$34,200	$35,400	$36,700
Equipment Move				
60% of move in/ move out estimates from Mob/demob	$11,500	$11,500	$24,000	$40,000
Total for a Move Around	$44,700	$45,700	$59,400	$76,700

IV. CONCLUSIONS

The allowances for pre-cleaning and reinstatement of connections are not going to be needed for all pipeline segments that will be hydrotested. As such, these costs should be included only for cases where there is a true requirement.

PG&E needs to rework the definition of the work tasks and where each task belongs to better define the hydrotesting costs.

Hydrotesting costs are a function of the time it takes to fill the pipeline with water and empty it of water and dry it out. The costs for mobilization/demobilization and move around are a function of size of the access holes and the amount of equipment to be moved. Pipeline cleaning is not part of hydrotesting.