South Rim Expansion

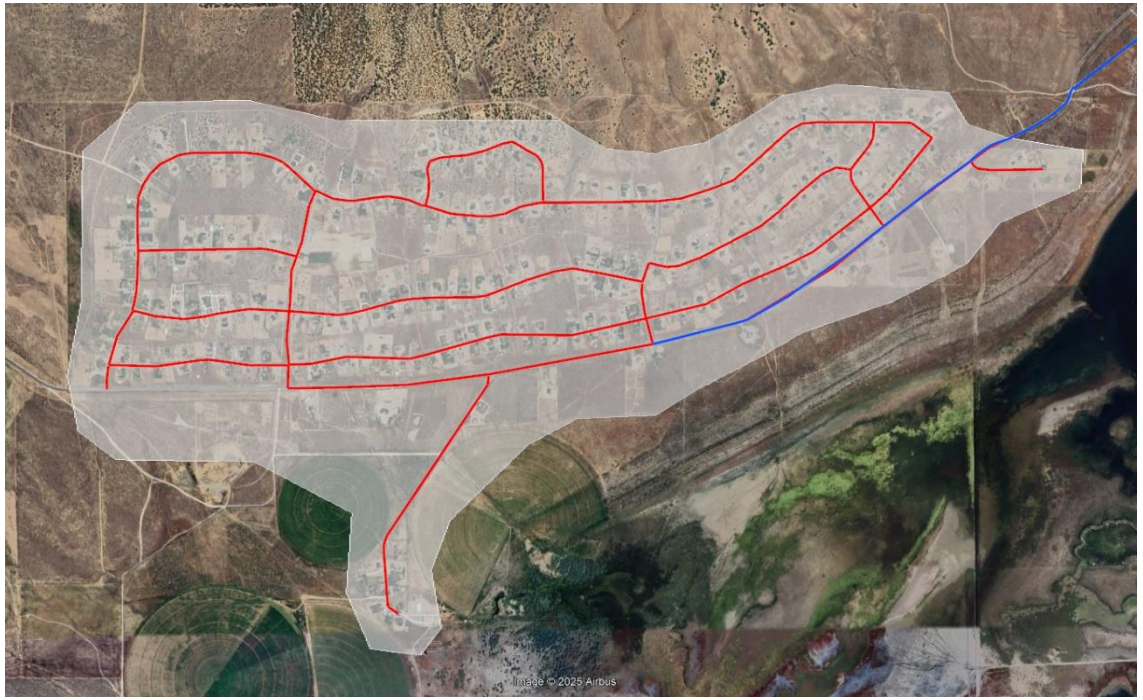
Technical Conference

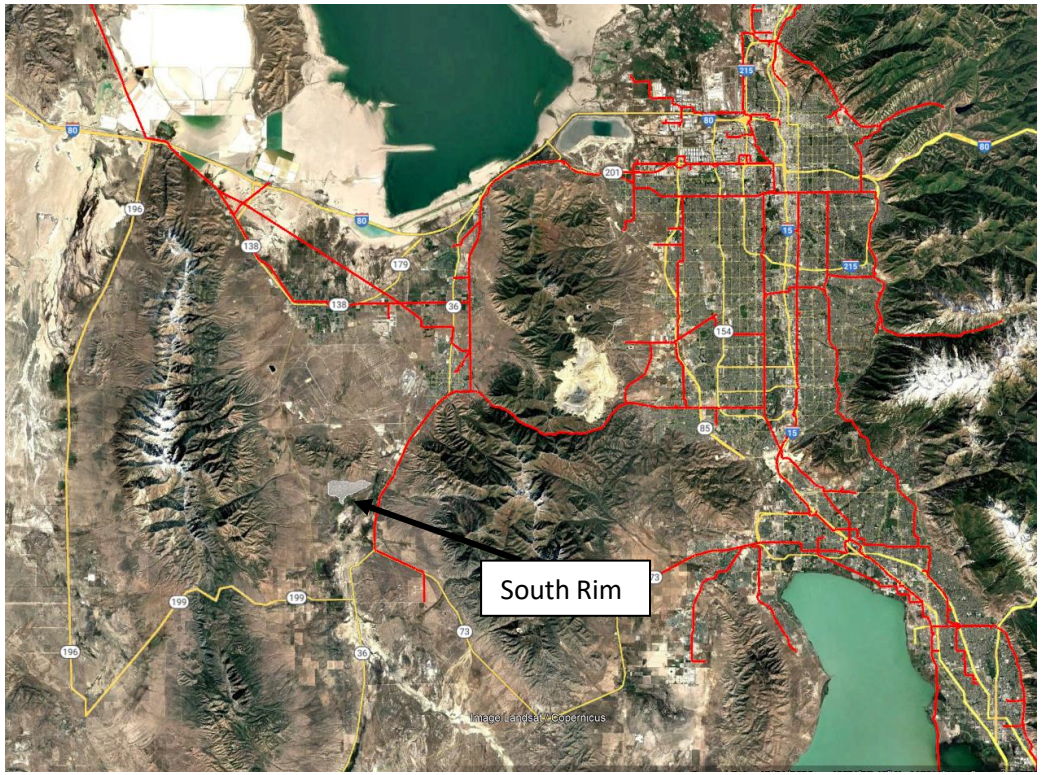
Docket No. 25-057-21

Scope

- 356 Potential customers
  - Counted by service lines going to structures
- 16,510 feet of 6” high-pressure pipe
- 68,975 feet of IHP pipe
  - 54,575 ft of 2”, 300 ft of 4”, and 14,100 ft of 6”
- 50,700 feet of service line
- New regulator station

Geography





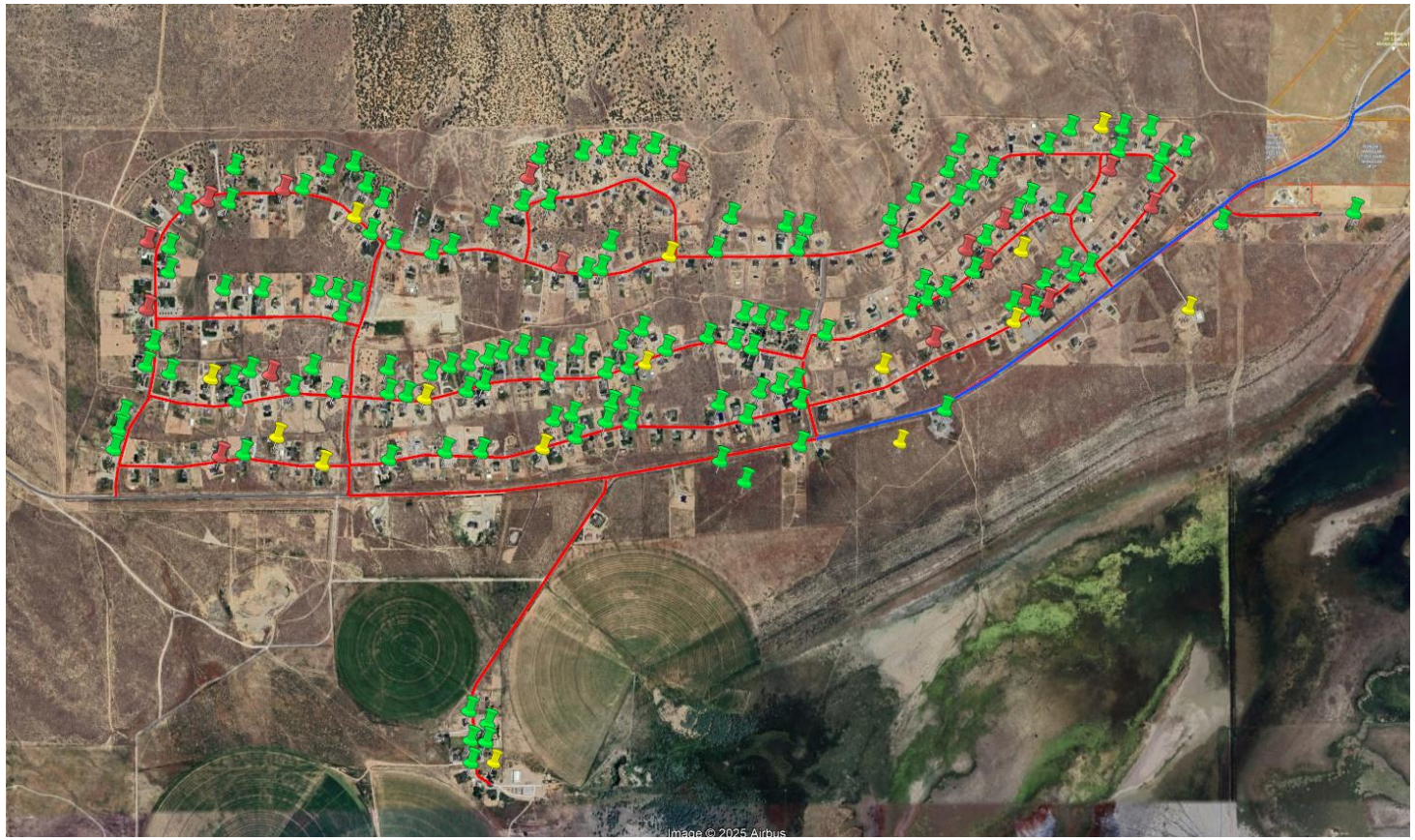
Customer Interest

- Web page on Enbridgegas.com
- https://www.enbridgegas.com/about-enbridge-gas/projects/utah-rural-expansion
- Open House on June 10, 2025
- Surveys
- Door Hangers

Survey Responses

Are you interested in receiving natural gas service?

- 135 “Yes” Responses
- 11 “Unsure” Responses
- 19 “No” Responses



Spending Caps

- DNG from most recent general rate case = $481,158,558
- 2% of DNG = $9,623,171
- 5% of DNG = $24,057,928
- Used tracker model to add investment

	2% cap Mains Revenue Requirement	5% cap Mains Revenue Requirement
Total Net Investment	$88,659,061	$221,647,658
Less: Amount currently in rates	$0	$0
Replacement Infrastructure in Tracker	$88,659,061	$221,647,658
Less: Accumulated Depreciation	($1,140,747)	($2,851,867)
Accumulated Deferred Income Tax	(5,613,024)	(14,032,560)
Net Rate Base	$81,905,291	$204,763,232
Current Commission-Allowed Pre-Tax Rate of Return	8.46%	8.46%
Allowed Pre-Tax Return (Line 6 x Line 7)	$6,929,188	$17,322,969
Plus: Net Depreciation Expense	$1,711,120	$4,277,800
Net Taxes Other Than Income (1.2% x Line 6)	$982,863	$2,457,159
Total Revenue Requirement	$9,623,171	$24,057,928
Increase in revenue requirement in 3-year and cumulative windows (See EGU Exhibits 1.12 and 1.13)	$8.3 Million	$16.5 Million
Combined revenue requirement in 3-year and cumulative windows (See EGU Exhibits 1.14 and 1.15)	$9.3 Million	$17.5 Million

Q1. Ancillary Costs

- Estimated 2025 Replacement Costs in Salt Lake County, Utah
  - > Conversion Kits: $15 - $300
  - > Water Heater: $1,000 - $2,900
  - > Furnace: $3,200 - $8,400
  - > Additional costs depend on extend of work required:
    - – Fuel Lines
    - – Duct work
    - – Venting

1. Please provide a more detailed list of "ancillary costs" new gas customers might experience: (i.e., new HVAC units, higher contractor costs, etc) along with the expected amount of each one.

Q2. Conversion Costs

- The Company has not conducted an analysis on household income in the area.

2. Has EGU analyzed the median household income in the area vs. the cost of converting to gas appliances? If so, please provide evidence to demonstrate that the potential customers in this area have financial viability to afford the cost of converting their properties to natural gas.

Q3. Conversion Costs

- Survey Results (EGU Exhibit 2.03)
  - > 81% of residents expressed interested in receiving natural gas service

Project	Potential Customers	Services Installed As of 10/1/2025	Meters Installed As of 10/1/2025
Eureka 19-057-31	360	289	263
Goshen/Elberta 21-057-06	379	327	283
Green River 21-057-12	483	326	224
Genola 23-057-13	507	330	167
Portage 24-057-13	107	44	5

3. What evidence does the Company rely on to be confident that customers in this area will be able to afford converting their appliances and or/ buying and installing new appliances, in order to be connected to gas service to be offered?

Q4. Low Income

- The Company has not calculated the number of potential customers who would qualify for Low Income assistance or rebates.
- Income verification for low-income assistance is done through the Utah Department of Workforce Services Housing and Community Development Agency

4. Has EGU calculated the number of potential new customers in the area that may qualify for Low Income assistance or other rebates? If so, please provide that information.

Q5. Financial Impact of Low Income

- The Company has not calculated the number of potential customers receiving low-income assistance/rebates impact on overall cost-of-service/rate base.

5. What is the financial impact of these potential customers receiving low-income assistance/rebates on the overall cost of service/rate base?

Q6. Cost Recovery

- Estimated annual savings with natural gas:
  - > $1,127.95
    - – EGU Exhibit 1.17.

6. After switching their appliances to be eligible for natural gas services, how long would it take for an average customer (using 70 Dth/year) to see a return on their investment (based on the assumption that natural gas prices are lower than their current heating source) and thus resulting in lower bills?

Q7. Rural Vs Urban Community Cost

South Rim Estimated Cost	
Estimated Project Cost	$23,994,707
Count of Potential Customers	356
Average Cost per Customer	**$67,401**

Average Cost to Add Customer (main line, service line, and meter)	
Contributions in Aid of Construction (CIAC)	$2,724
Company Contribution	$3,156
Average Cost per Customer	**$5,880**

7. What is the average cost of connecting this rural community versus connecting an average urban community like a new subdivision?

Q8. Development Plans

- EGU has not corresponded with any developer.

8. Can EGU provide additional information about what developments are planned in the next 5-10 years, according to Thomas' testimony?

Q9. Propane vs Gas Costs

- 2024 Propane Costs from EIA
  - > Winter: $2.29 - $2.48
  - > Summer: $2.21 - $2.35

- EGU Exhibit 1.17

	A	B	C	D	E
				Annual Saving Using Natural Gas vs Propane	
		Gallons used per year	Price per gallon	Annual delivery & rental Fees	Estimated Annual Cost	
1	Propane	764	$2.21	$100.00	**$1,791.92**	Estimated Annual Savings with Natural Gas
		DTH used per year	Price per DTH	Monthly Base Charge	Estimated Annual Cost	
2	Natural Gas	70.0	$8.33	$6.75	**$663.98**	$1,127.95

9. Please provide a cost comparison of propane vs natural gas prices in the summer vs winter for this area.

Q10. Depreciation of Assets

- Treated like all other plant – This is no difference than any other community.
- Commission Order dated August 27, 2020 in Docket No. 19-057-31, Company's expansion to Eureka, Utah.

We do not interpret either Utah Code Ann. § 54-17-40(3)(b)(ii) or Utah Admin. Code R746-440-1 as requiring a cost benefit analysis in this Docket. While all other project acquisitions under the Voluntary Resource Decision Act must demonstrate that the acquisition will most likely result in the lowest reasonable cost project for customers as set forth in Utah Code Ann. § 54-17-402(3)(b)(i)(A), a rural infrastructure development is not subject to the same showing. The public interest inquiry for rural gas infrastructure developments is unique and includes consideration of entirely different factors. Whereas we acknowledge that a cost benefit analysis would be useful in the public interest determination applicable to project acquisitions requiring a showing of "lowest reasonable costs," it is not as useful (nor is it required) for a rural gas infrastructure development like the Eureka Rural Expansion Project. Accordingly, we conclude DEU provided information that both is sufficiently reliable and appropriately satisfies the requirements in our applicable statutes and rules . . . .

10. Will the project collect its full cost recovery by the time the pipes are fully depreciated based on an average customer's use of 70 Dth/yr?

Q11. Projected Growth

- Standard practice to consider growth
  - > Anticipate residential, commercial and industrial demands driven by natural gas serving the new area
    - – Community contact
      - Approved land use (zoning of city)
      - Population and household growth rates
      - Economic development projects

11. Exhibit 2.05 states that the proposed project is sized for growth. Please provide the projected growth this is based on.

Q12. Cost of Existing Load

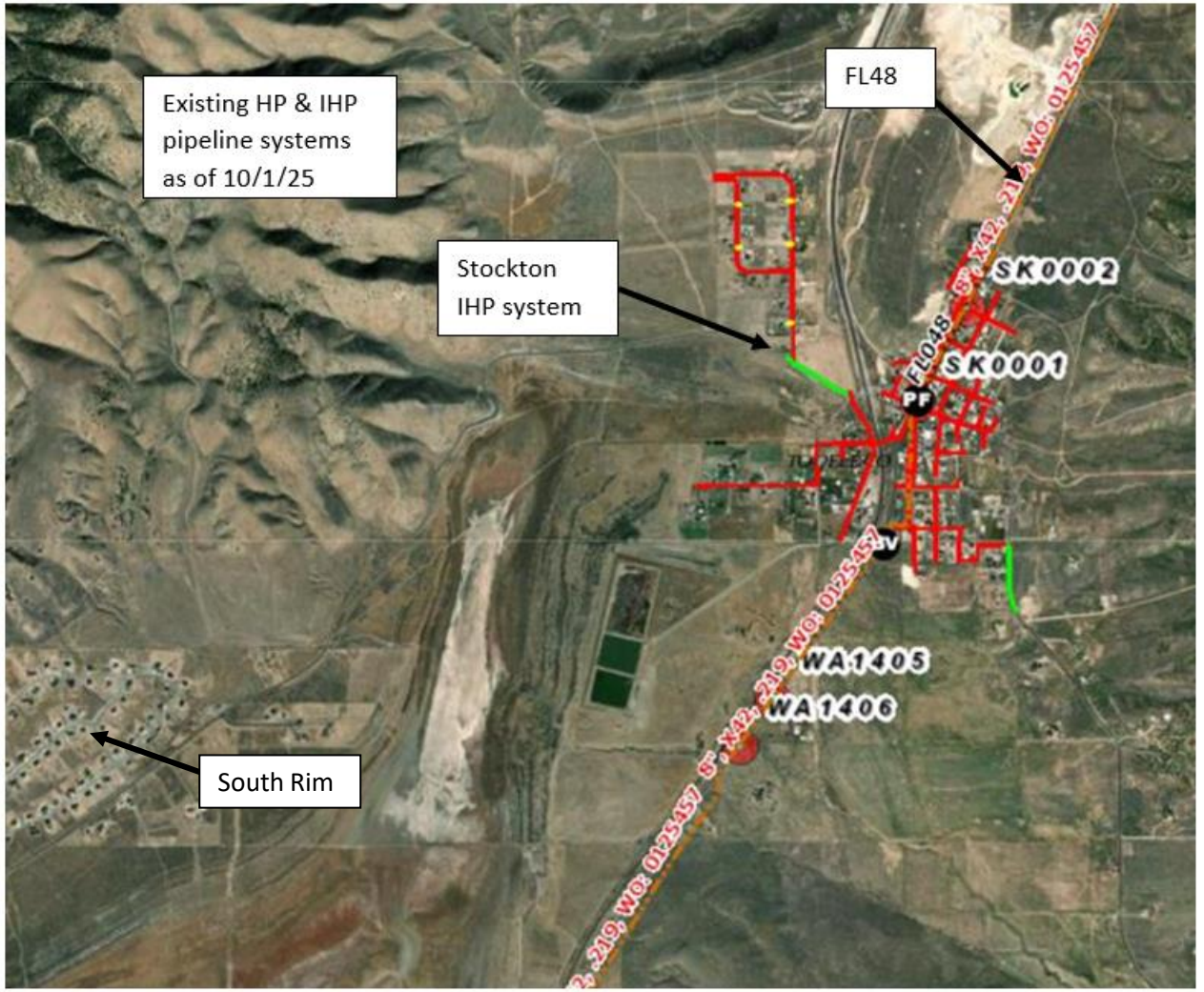
- No, 2” IHP main feed cannot serve the design load calculated in EGU Exhibit 2.04 from the proposed pressure regulator station.

- Minimum size required: 4” IHP main feed for existing load
  - > Limitation: provides little additional capacity for future growth

12. Will a 2” primary feed would be adequate for existing load. What would the cost be to serve only the existing load?

Q13. System Map

- There are no scheduled project installations between 10/1/2025 and March 2026.
- The South Rim expansion project will be constructed between April 2026 through November 2026 following Commission approval .
- Planned in-service date: system would be end of November 2026.



13. Please provide updated system maps from Exhibit 2.06 with
a. Existing pipe as of 10/1/2025
b. Scheduled project installations until March 2026
c. Proposed timeframe of expansion after Order is issued

Q14. Cost Tracking

- All internal labor, materials, administrative overheads, contractor costs and other related expenses are recorded against unique project numbers created for:
  - > High-pressure pipeline
  - > Pressure regulator station
  - > Regulator station property purchase
  - > IHP mains installations
  - > IHP service line installations.

14. After the cost estimate is approved, please provide an explanation of how hours/expenses are tracked internally.

Q15. Project Budget

- If the project comes in under budget, then the funds will be spent on other capital projects at the discretion of Engineering and Operations management.

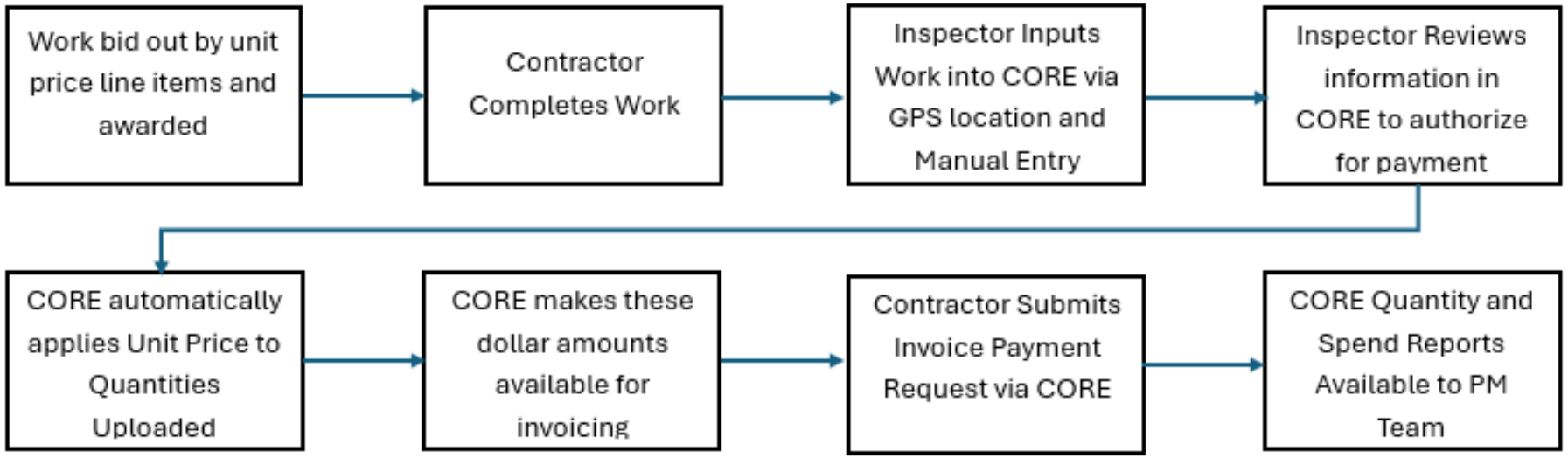
15. Please explain what the Company would do with the extra funds, should the project be under budget?

Q16. Contractor Costs

- HP Pipeline & Pressure Regulator Station Contractor Work
  - > Company inspectors track and review work units in the field
    - – End of each week, contractor and Company inspector approve work tracked in a spreadsheet
      - Spreadsheet sent to Engineering for review and record keeping
  - > Contractor creates invoice based on approved spreadsheet
    - – Project Manager reviews and approves invoice

16. How are the contractor costs calculated, tracked and verified?

IHP Cost Tracking Workflow



- Core is the software system used to track IHP Costs

16. How are the contractor costs calculated, tracked and verified?

Q17. Unique Challenges: Superfund Site

- Superfund Site
- Wetlands
- Easements

17. Is there anything unique or challenging regarding this project? I.e., permitting, easements and/or environmental concerns that could affect the cost? If so, please provide an explanation and cost estimate.

Q18. Capacity Differences

- There would not be any significant capacity differences between options A and B.

18. What are the capacity differences between option A and option B?

Q&A

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